SHORT TERM ECONOMIC

LOAD ALLOCATION

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ABSTRACT

The method of equal incremental cost of received power is well established as a means of determining the most economic distribution of active power, while satisfying the power system load demand, subject to generation and water constraints.

This report considers the concepts and implications of the method, in applying it to part, or all, of the New Zealand Power System. A digital computer program, developed as part of this report, is described which implements the method on a model of the South Island subsystem of the New Zealand Power System and provided the necessary computational experience to evaluate some of the important aspects of economic scheduling with this method.

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CONTENTS

Page No.

SECTION 3 : DIGITAL COMPUTER PROGRAM LANZOP

SECTION 4 : RESULTS, CONCLUSIONS AND RECOMMENDATIONS

SECTION 1

INTRODUCTION

1.1 Optimal Operation of a Power System

This report considers the optimal operation of a power system from an economic point of view. The aim of economic operation is to meet the system load demand as it varies over a given time period, at the minimum total cost while complying with the physical limits imposed by the system.

With the advent of large high-speed computers it is now possible to consider load scheduling (i.e., the distribution of generation to meet the load) in much greater detail and to determine the schedule of available generation in a large system, much more accurately than possible previously.

The optimal operation of an integrated power system (both hydro-electric and thermal generation in the system) is a complex task as each type of generation has its own peculiar characteristics and limitations. This complexity makes it necessary to divide the overall system problem into a number of subproblems which can be considered independently, even though the subproblems are in fact interconnected and not totally independent. Economic operation of a power system may be considered as a subproblem with interaction among other subproblems such as system security, system planning. There are a number of ways in which this division may be made, one of the most usual being undertaken on a time basis.

This permits division into two main streams -

(i) Long term operation

(ii) Short term operation

1.1.1 Long Term Operation:

The long term operation of a power system may be further divided into two time periods, namely, the planning period, and the operational control period. In this report, long term operation will refer to the operational control period, which may be considered to range from one week to three years, while the planning time period may range upward of three years and is principally concerned with the "why, when and where" of the installation of equipment in the system.

The long term operation, then, in an integrated system is concerned with the allocation of energy resources to ensure continuity of supply, at a minimum cost. In order to achieve these objectives, the use of the water and the thermal resources must be co-ordinated so that at any time -

(a) the thermal costs are not made excessive by an endeavour to preserve a more than adequate reserve of water for later use in the system, or,

(b) the thermal costs are not minimised to such an extent that the water resources are depleted, and the continuity of supply is placed at risk.

The decision on the distribution of generation between the two basic resources is the important long term decision, but the results of this must be reflected in the short term operation of the system.

1.1.2 Short Term Operation:

The short term operation is concerned with daily or weekly operation of the system subdivided into suitable time intervals. The available generation, system maintenance requirements, and the constraints imposed by transmission limitations must be considered during these time intervals, and the water allocation for the time period should be achieved. The aim of economic allocation in the short term is to minimise the total cost subject to the above constraints while ensuring satisfaction of the load demand.

The following cost factors are significant in considering the total cost of a power system:-

(i) New capital works

(ii) The servicing of loan moneys and depreciation

(iii) Administrative costs

(iv) Maintenance and labour

(v) Fuel for thermal plant

The first four costs can be considered as fixed costs in the short term, and consequently the only variable cost in the short term which is directly applicable to the operation of the system is that of the thermal station fuel. The total fuel cost then, is the basic input cost of the system, and the criterion for optimal economic operation becomes the minimisation of the cost of thermal generation. (There are other less significant costs, which if they can be related directly to the system generation, such as gas turbine maintenance, may be added as a small cost component to the total fuel cost.)

The long term optimization results in water constraints (water allocation) which must be considered in the short term, and generally the water to be used in a given catchment or plant is then defined for the short term[1]. The value or cost of water may then be indirectly related to the storage requirements in the water reservoirs, and the most probable replacement value of the equivalent generation from thermal plant. The assignment of a value to the water in each catchment or hydro-electric plant is necessary to enable the calculation of the optimum economic generation schedule to be made.

1.2 Economic Load Scheduling Techniques

The classical load dispatching methods deal with the economic allocation of active generation only. These methods may or may not include the system transmission losses depending upon the significance of these losses in the system being modelled.

A closely linked network, with thermal plant at major load centres may not require the consideration of the losses. However, if they are included, the usual methods of describing the system transmission network do not impose constraints upon this model, the assumption being made that the network is capable of distributing the power as scheduled satisfactorily in all cases. This assumption is often too generalised and methods are being developed to overcome this weakness of the classical methods. The only constraints normally considered in each time interval, when scheduling active power are the maximum and minimum generation limits.

The classical methods may be divided into two main categories, that of "merit order" scheduling, and that of "equal incremental cost" scheduling. The "merit order" method[2] is used principally in large thermal systems such as that of the British Central Electricity Generation Board, and is based on the cost of generation at each station derived from the thermal performance of the plant and the cost of the fuel supplied to that station. The generation is dispatched so that the overall cost of generation is minimised with due regard to the security of supply. This means that the large and most modern stations with the lowest incremental cost are scheduled first as base load stations, with the next least expensive stations being loaded sequentially until the load demand is satisfied. This method does not involve significant hour to hour computation and is easily carried out.

The "equal incremental cost" methods invoke the principle that the load should always be taken up at the lowest incremental cost, that is, the most economical distribution of generation occurs when all plant is operating at the same incremental cost within their operating capacity.

These methods involve a large amount of computation even for a relatively simple system and hence the development of incremental cost slide rules and with the advent of computers, programs for the complex calculations. (The "merit order" method may be considered as a simple form of the "equal incremental cost" method, as the merit order is established by the incremental cost of the plant, the incremental cost characteristic being constant and independent of the output.)

For an integrated system, where there is significant hydro generation, the "merit order" approach is not particularly practical, as the overriding constraints in a hydro system are the water allocation constraints which are predetermined from the long term considerations. Hence the development of the "equal incremental cost" method for integrated power systems and the purpose of this report is to discuss the theory behind the method and its application to the New Zealand Power System.

1.3 Requirements of Load Allocation Methods

Any method used for load allocation scheduling should meet the following requirements:-

(i) Simple to use

(ii) Minimum input information required

(iii) Short computation time compatible with the time scale of the load allocation schedule

(iv) Easily interpreted results

With the increase in system complexity, manual methods no longer meet these requirements, but with the availability of high speed digital and analogue computers, complex systems may now be handled, and the above requirements satisfied. Both analogue and digital methods have been developed, but in this report only the implementation on a digital computer has been considered. The analogue computer has a significant role to play in on-line applications of system control, particularly for inter-area economic allocation as developed by a number of Electric Power Supply utilities in the U.S.A. The chief disadvantages of analogue computers are their high cost and relatively specialised use, which may be justified for their automatic control applications and high speed operation in a large system.

1.4 Economics of Computer Calculation

The implementation of a suitable method by computer may result in significant savings in power station operation. Electric power generation represents a significant factor in the national economy. Effective utilisation of the resources available reduces the expenditure of capital on equipment, and realizes the maximum capability of the resources. A small error in the co-ordination of these resources therefore, can cause unnecessary expenditure. Computer based calculations -

(i) Reduce costs by:

(a) accurate computation

(b) including factors (e.g., transmission losses) which are usually omitted in manual methods.

(ii) Reduces the manpower required and allows the realignment of this manpower to other duties.

The savings possible above are offset by the high annual cost of computer operation, and the use of the computer and its facilities may need optimizing to prevent excessive computing time for marginal gain in savings.

In implementing economic load allocation by computer, it must be remembered that the economic scheduling is but one aspect of the optimizing of the total Power System operation which can now be achieved with the aid of the high speed computer.

SECTION 2

THE CONCEPTS OF SHORT TERM OPTIMIZATION

2.1 Development of Co-ordination Equations

The problem of short term optimization for a combined hydro-thermal (integrated) power system is that of minimising the total input into the system while satisfying the current load demand and the constraints imposed by the system itself and the constraints imposed by management.

In allocating the generation the overriding constraint which must be met is that of the system load demand. (As discussed in Section 1, the discussion will be limited to that of real (active) power allocation.)

This may be represented thus -

$$\sum_{i}^{n} P_i - P_L - P_R^d = 0 \qquad (1)$$

where P_i = the power output of Plant i (MW)

P_L = the system transmission losses (MW)

P_R^d = the system load demand (MW)

n = the number of power plants (both thermal and hydro)

In an integrated power system, the total input cost can be considered as the total fuel cost for the thermal stations.

Hence -

$$F_t = \text{total cost } (\$/\text{hr})$$

$$= \sum_{i=1}^{\alpha} F_i$$

where α = the number of thermal stations

i = 1, ...α

and F_i = the fuel cost for plant i (\$/hr)

The short term optimization requires that -

$$\int_{t_o}^{t} F_t \, dt = \text{minimum}$$

where $t-t_o$ = the fixed time period defining the short time interval

Since the time period is broken up into discrete time intervals, the object is to minimise -

$$\sum_{t_o}^{t} \sum_{i=1}^{\alpha} F_i \quad \Delta t$$

In addition to the demand constraint applying for each interval, the long term water resource allocation will impose water constraints on the system. Therefore the total input cost must be minimised subject to the water constraints -

$$\sum_{t_o}^{t} W_j \quad \Delta t = K_j$$

where W_j = the turbine discharge of hydro plant j (cusecs)

= $W_j\ (P_j)$ a function of the generation from plant j

K_j = water allocated for plant j

As stated in Section 1, one criterion which can be used to achieve optimum scheduling is for all generation sources to be operated at equal incremental cost. This concept can be arrived at intuitively. Assume that all generation sources are not operating at the same incremental cost. Consequently some sources would be operating at a higher incremental cost than others. It would then be possible to reduce the system input by decreasing the generation on the higher cost source and increasing the generation on the lower cost source. In the limit, all sources should be operated at the same incremental cost. This is expressed in the statement of the so-called Co-ordination Equations:

$$\frac{dF_i}{dP_i} + \lambda \frac{\partial P_L}{\partial P_i} = \lambda \quad \text{for thermal plant} \qquad (2)$$

$$\gamma_j \frac{dW_j}{dP_j} + \lambda \frac{\partial P_L}{\partial P_j} = \lambda \quad \text{for hydro plant} \qquad (3)$$

that is, the minimum input cost for a given system load demand is obtained when the incremental cost of generation at a given plant plus the cost of the incremental transmission losses associated with that generation charged at the system incremental cost is the same for all generation plant.

Consider equation (2) for the thermal plant[3]

Let F_i = input to plant i (\$/hr)

F_t = total input to the system (\$/hr)

then $F_t = \Sigma F_i$

let P_L = total transmission losses (MW)

and P_R^d = system load demand = P_R (MW)

P_R = received power (MW)

To achieve the optimum allocation, it is necessary to minimise total input F_t -

let $F = F_t - \lambda\psi$

applying the method of Lagrange multipliers where

λ = Lagrange multiplier.

The constraining relationship is given by -

$$\psi(P_1, P_2, P_3 \ldots\ldots\ldots\ldots P_i) = \sum_i P_i - P_L - P_R$$
$$= 0$$

Minimum input for a given load is obtained when -

$$\frac{\partial F}{\partial P_i} = 0$$

then $$\frac{\partial F}{\partial P_i} = \frac{\partial F_t}{\partial P_i} - \lambda \frac{\partial \psi}{\partial P_i} = 0$$

$$\therefore \quad \frac{\partial F_t}{\partial P_i} - \lambda \frac{\partial}{\partial P_i} \left(\sum_i P_i - P_L - P_R \right) = 0$$

and hence $$\frac{\partial F_t}{\partial P_i} + \lambda \frac{\partial P_L}{\partial P_i} = \lambda$$

now $F_t = \sum_i P_i \quad \therefore \frac{\partial F_t}{\partial P_i} = \frac{\partial (\Sigma F_i)}{\partial P_i} = \frac{\partial F_i}{\partial P_i} = \frac{dF_i}{dP_i}$

then $\frac{dF_i}{dP_i} + \lambda \frac{\partial P_L}{\partial P_i} = \lambda$

The thermal plant co-ordination equation where -

$\frac{dF_i}{dP_L}$ = incremental plant cost at plant i ($/MWh)

$\frac{\partial P_L}{\partial P_i}$ = incremental transmission losses associated with plant i (MW/MW)

λ = incremental cost of received power ($/MWh)

The incremental transmission losses are costed by charging them at the incremental cost of received power.

In a similar manner[4] the co-ordination equations (2) and (3) can be derived for an integrated power system from the equation of constraint -

$$\Sigma P_i + \Sigma P_j - P_L - P_R^d = 0$$

subject to $\sum_{t_o}^{t_1} W_j \quad \Delta t = K_j$

where ΣP_i = total thermal generation (MW)

ΣP_j = total hydro generation (MW)

W_j = water flow from plant j (cusecs)

K_j = allocated water (cu.ft)

t = $t_1 - t_o$ = optimization period

and as before $\sum_{t_o}^{t_1} F_t \quad \Delta t$ = minimum is required

Then the co-ordination equations (2) and (3) are -

$$\frac{dF_i}{dP_i} + \lambda \frac{\partial P_L}{\partial P_i} = \lambda$$

$$\gamma_j \quad \frac{dW_j}{dP_j} + \lambda \frac{\partial P_L}{\partial P_j} = \lambda$$

where $\frac{dW_j}{dP_j}$ = incremental water rate of hydro plant j (cusecs/MW)

γ_j = cost of water ($/(cu.ft x 10^6) say)

and then $\gamma_j \frac{dW_j}{dP_j}$ = incremental plant cost of hydro plant j

The γ_j constants are the set of Lagrange multipliers chosen so that the allocated amount of water is used by each hydro plant, and is effectively a conversion coefficient which converts incremental water rate to incremental plant cost. The derivation assumes that during the given time period, the operating head of each hydro station is constant, and this is implied in the constant conversion coefficient γ_j.

2.2 Transmission Losses

The co-ordination equations derived include the effect of the system transmission losses.

Without these losses the equations reduce to -

$$\frac{dF_i}{dP_i} = \lambda$$

$$\gamma_j \quad \frac{dW_j}{dP_j} = \lambda$$

that is; all plant operates at the same incremental plant cost which is equal to the system incremental cost of received power.

The system transmission losses need to be considered in order to achieve optimum economy since ignoring these losses does not penalise generation plant which may have significant transmission losses associated with it[5]. Kirchmayer and Stagg in reference 5 have shown that including the incremental transmission losses substantially reduces the fuel cost.

2.2.1 Evaluation of Transmission Losses:

The evaluation of the transmission losses and the corresponding incremental transmission losses has been greatly facilitated by the development of transmission loss formula expressing the losses in terms of generator power (the source powers). The loss formula allows the losses to be calculated quickly and accurately. Rapid calculation of losses must be possible in any method of co-ordination because of the large number of times they are evaluated during the production of an economic load schedule, when scheduling on the basis of received power equal to demand.

The loss formula in its full form is -

$$P_L = \sum_m \sum_n P_m B_{mn} P_n + \sum_n B_{no} P_n + B_{oo} \qquad (4)$$

where Σ is summation of powers P_n

B_{mn}, B_{no}, B_{oo} are the derived transmission loss formula coefficients

The full expanded form of the loss formula allows better handling of non-conforming loads and the assumptions involved in deriving the coefficients need to be less rigidly adhered to over a range of operating conditions. It has been shown by Kirchmayer et al.[6] that the additional savings obtained by using the loss formula with the linear and constant terms are marginal, for a system of reasonable complexity, and for the purposes of this report the transmission losses will be evaluated using the standard Quadratic form.

$$P_L = \sum_m \sum_n P_m B_{mn} P_n = \text{total transmission losses} \qquad (5)$$

where B_{mn} = loss formula coefficients (a symmetrical n x m matrix)

P_n = generation of plant n

$m = n$ = number of generation plant

For a brief treatment of the derivation of the transmission loss formula and the B coefficients refer to Appendix B.

From equation (5), the incremental transmission losses are -

$$\frac{\partial P_L}{\partial P_n} = \frac{\partial}{\partial P_n} \left(\sum_m \sum_n P_m B_{mn} P_n \right)$$

$$= 2 \sum_n B_{mn} P_n \qquad (6)$$

This form of the incremental transmission losses is very suitable for incorporation into the co-ordination equation as it involves only straight forward matrix multiplication, and it is in terms of the plant generation.

The co-ordination equations can now be written including the losses.

$$\frac{dF_i}{dP_i} + \lambda \left(2 \sum_i B_{mn} P_n\right) = \lambda \qquad (7)$$

and
$$\gamma_j \frac{dW_j}{dP_j} + \lambda \left(2 \sum_j B_{mn} P_n\right) = \lambda \qquad (8)$$

where m, n = total number of generation plant

In full, differentiating between hydro and thermal plant -

$$\frac{dF_i}{dP_i} + 2\lambda \left(\sum_{m=1}^{\alpha} B_{im} P_{Sm} + \sum_{n=\alpha+1}^{\beta} B_{in} P_{Hn} \right) = \lambda \qquad (7a)$$

$$\gamma_j \frac{dW_j}{dP_j} + 2\lambda \left(\sum_{n=\alpha+1}^{\beta} B_{jn} P_{Hn} + \sum_{m=1}^{\alpha} B_{jm} P_{Sm} \right) = \lambda \qquad (8a)$$

where i = thermal plant number $i=1, \ldots\alpha$

m = thermal plant number $m=1, \ldots\alpha$

j = hydro plant number $j=\alpha+1, \ldots\beta$

n = hydro plant number $n=\alpha+1, \ldots\beta$

α = total number of thermal plant

β = total number of generation plant

$\beta-\alpha$ = total number of hydro plant

Since the losses are calculated using the loss formula coefficients, the accuracy of the losses and hence the optimum schedule obtained are subject to the following assumptions which are inherent in deriving the B coefficients:-

(i) The equivalent load current at any busbar remains a constant complex fraction of the total equivalent load. The equivalent load current at the busbar is defined as the sum of the line charging, synchronous condenser, and load currents at that bus.

(ii) The generator bus voltage magnitudes and angles remain constant.

(iii) The ratio of reactive power to real power of any generation source remains constant.

These assumptions are necessary to allow the expression of the transmission losses in terms of generator powers only.

There is an alternative method of calculating the losses, in a form suitable for use in the co-ordination equations, based on the work of Brownlee[7] considering the losses as functions of the voltage phase angle. However, Kirchmayer has shown that in general, this method is less accurate than the B coefficient method in a system of reasonable complexity. This method has not been used extensively in power system operation and will not be discussed further.

The B coefficient loss formula describes the system losses in terms of generated power only, and therefore the system configuration from which they were derived is submerged. This fact and the need for the assumptions made, lead to a number of weaknesses in the method and hence in the results of the solution of the co-ordination equations. The principle weaknesses are -

(i) The system network must be of such a form so as to enable the satisfying of the assumptions used in the B coefficient derivation.

(ii) A solution may be obtained which is not physically realizable because of the limitations of voltage, active and reactive power, inherent in the system, as the B coefficients once derived do not take any limits into account.

(iii) Stability limits may be exceeded and an unstable power allocation scheduled.

(iv) No optimization of the reactive power component is considered, and hence a true power optimum is not obtained.

2.3 Methods of Solving the Co-ordination Equations

Consider equation (2) -

$$\frac{dF_n}{dP_n} + \lambda \frac{\partial P_L}{\partial P_n} = \lambda$$

as representative of all forms of the co-ordination equations. It is a non-linear equation in λ since the incremental transmission losses are charged at a rate equal to the incremental cost of received power (λ). There are three basic methods used in solving these equations -

(i) Exact solution of the non-linear simultaneous equations

(ii) Approximate solution by using linear simultaneous equations

(iii) Penalty factor method

2.3.1 The Non-linear Equations:

The non-linear equations must be solved iteratively for the power generation, since the value of λ is not known which satisfies the load demand. Within this iterative procedure, an inner iteration is required to calculate the losses and hence the generation since the losses are unknown until the power distribution is known.

2.3.2 The Approximate Solution:

If the incremental transmission losses are charged at a constant rate β which closely approximates λ then the resulting equations are linear.

$$\frac{dF_n}{dP_n} + \beta \frac{\partial P_L}{\partial P_n} = \lambda \qquad (9)$$

where β can be considered as the average cost of received power. Rewriting the above equation -

$$\frac{1}{\beta} \quad \frac{dF_n}{dP_n} + \frac{\partial P_L}{\partial P_n} = \frac{\lambda}{\beta} = \emptyset \qquad (9a)$$

if $\emptyset = 1$ then the equations correspond to the exact non-linear equations.

2.3.3 The Penalty Factor Method:

The penalty factor method charges the incremental transmission losses at a rate corresponding to the incremental plant cost, when using the approximate penalty factor L_n'.

From equation (2) -

$$\frac{dF_n}{dP_n} = \lambda \left(1 - \frac{\partial P_L}{\partial P_n}\right)$$

the penalty factor L_n is defined as

$$= \frac{1}{(1 - \frac{\partial P_L}{\partial P_n})} \qquad \text{for plant n}$$

then $\frac{dF_n}{dP_n} L_n = \lambda$

the solution of which is identical to that of the exact solution. This exact penalty factor is usually approximated by -

$$L_n' = \text{approximate penalty factor}$$

$$= (1 + \frac{\partial P_L}{\partial P_n})$$

and co-ordination equation becomes:

$$\frac{dF_n}{dP_n} L_n' = \lambda$$

The results are a close approximation to the exact solution since $(1 - \frac{\partial P_L}{\partial P_n}) \doteqdot 1$.

2.3.4 Evaluation of Methods:

Kirchmayer and Stagg (reference 5) have evaluated these three methods of co-ordinating the incremental plant costs and incremental transmission costs in detail. They conclude after study and their application to the American Gas and Electric Company's system -

(i) The operating economy obtained by scheduling generation by linear simultaneous equations and the penalty factor methods is for all practical purposes identical to that obtained by solution of the exact non-linear equations.

(ii) For large integrated systems, savings of considerable magnitude can be realized when the effects of the transmission losses are included in the economic schedule of generation.

Chandler, Dandeno et al.[8] also considered three alternative methods, and applied them to the Ontario Hydro integrated system.

(i) Exact solution of co-ordination equations

(ii) Equal incremental plant costs (i.e., ignoring transmission losses)

(iii) Maximum efficiency operation of hydro plant, with thermal plant scheduled by -

(a) Equal incremental fuel cost

(b) Exact co-ordination equations

The results of this study showed clearly the superiority of the co-ordination equations (with transmission losses) over the other methods considered.

Therefore the two approaches, the exact and approximate solution of the non-linear co-ordination equations are those best suited for economic scheduling. However, in using the approximate solution, (i.e., equation 9) -

$$\frac{dF_n}{dP_n} + \beta \frac{\partial P_L}{\partial P_n} = \lambda$$

the choice of the value of β is extremely important[3, 5]. The effect of increasing β is to emphasize the transmission losses, and may result in a solution approaching that of operating with minimum transmission losses, which is not that of minimum cost. Therefore care must be taken in choosing a value of β so that the linear solution is a close approximation to the exact solution. This may mean considerable work itself and in this report, the exact solution of the co-ordination equations has been applied, in gaining experience with the methods, to the New Zealand Power System.

2.4 Load Demand Variation

The variation of the daily load cycle may be taken into account by subdividing the load cycle into a number of loading periods and calculating a set of B coefficients corresponding to each of these loading periods (figure 2.1). Each set of coefficients can then embody not only the load distribution, but also the typical system configuration during that period. Kirchmayer and Stagg[5] show that although small variations occur between the B coefficients for the various loading periods because of changes in the loading period and generation parameters, an average value of these coefficients may also be applied over the whole daily load cycle without significant change to the optimum schedule.

2.5 Derivation of Incremental Plant Cost

2.5.1 Thermal Plant:

The incremental plant cost for a thermal station is usually considered as the incremental fuel cost derived from the incremental fuel rate, which is defined thus:

$$\text{Incremental fuel rate} = \frac{\Delta\,(\text{input})}{\Delta\,(\text{output})}$$

$$\text{in the limit} = \frac{d\ (\text{input})}{d\ (\text{output})}$$

The incremental fuel cost is then equal to the incremental fuel rate x fuel cost.

$$\text{I.F.C. (\$/MWh)} = \text{Fuel Cost (\$/BTU} \times 10^6) \times \text{I.F.R. (BTU} \times 10^6/\text{MWh)}$$

The representation of the incremental fuel cost for calculation purposes can be done in several ways of which the most usual are:-

(i) Step representation

(ii) Single straight-line approximation

(iii) Multisegment approximation as an extension of (ii)

See figure 2.2 (example, Marsden Power Station).

The step representation is rarely used for thermal plant because of the steadily increasing characteristic of the incremental fuel cost. The straight-line approximation is favoured, if a close approximation can be obtained, as it simplifies calculation. As increasing accuracy is required, "higher order" representation is necessary leading to multisegment approximations[3] to avoid significant loss in operating economy, but more sophisticated computing techniques are then required.

The straight-line equation for the incremental fuel cost is simply stated -

$$\frac{dF_n}{dP_n} = F_{nn}\ P_n + f_n$$

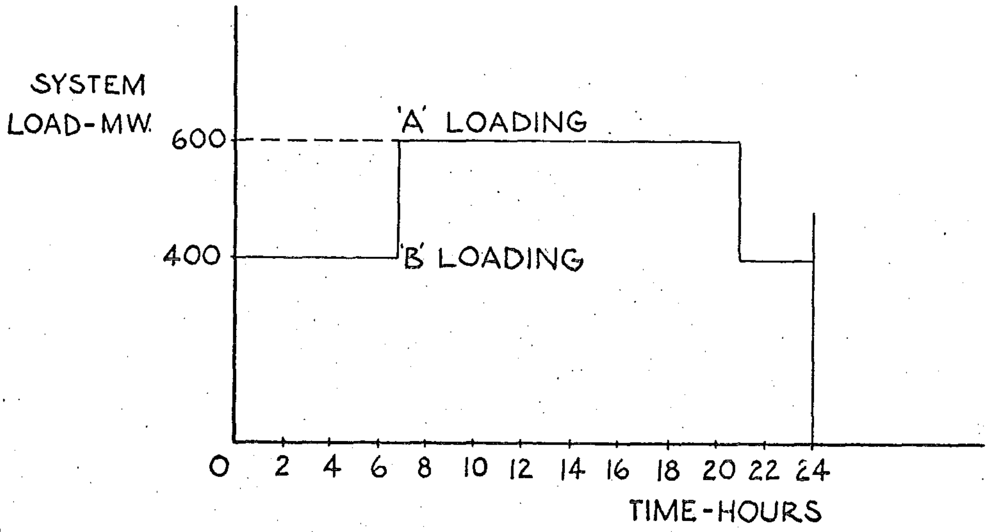

fig. 2·1 LOAD CYCLE VARIATION

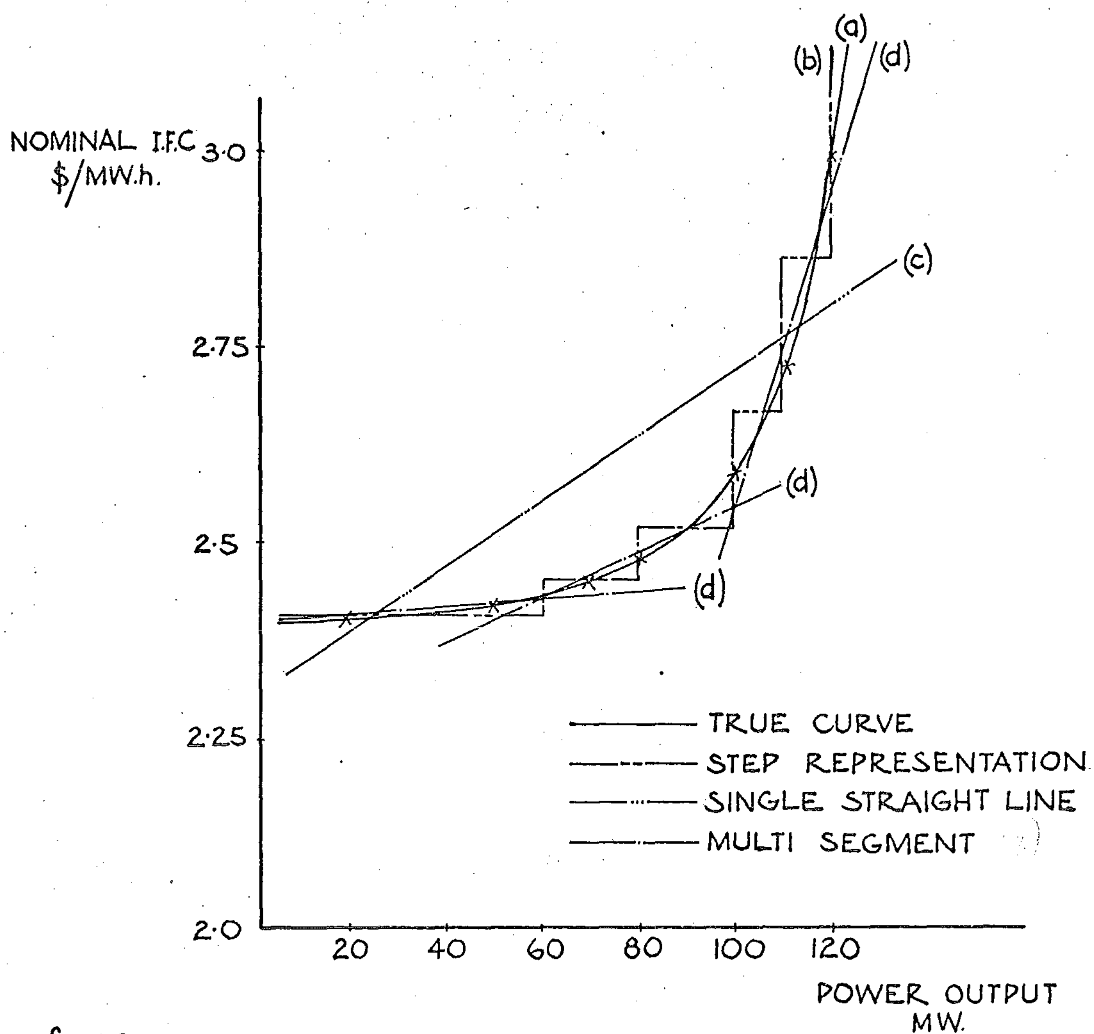

fig 2·2 INCREMENTAL FUEL COST OF THERMAL STATION
(EXAMPLES OF REPRESENTATION)

where P_n = generation of thermal plant n

F_{nn} = slope of incremental fuel cost curve

f_n = intercept (constant term) of I.F.C. curve

For multisegment representation this is extended -

$$\frac{dF_n}{dP_n} = F_{nn_1} P_n + f_{n_1} \qquad L_o \leqslant P_n \leqslant L_1$$

$$\frac{dF_n}{dP_n} = F_{nn_k} P_n + f_{n_k} \qquad L_{k-1} \leqslant P_n \leqslant L_k$$

where L_o, $L_1 \ldots L_k$ are generation limits defining the range of each segment.

k = number of segments.

From the station input/output curve, the station heat rate curve can be obtained as the derivative of the input/output curve. From these curves the incremental fuel rate curve is derived.

See figures 2.3, 2.4 and 2.5.

2.5.2 Hydro-electric Plant:

The incremental plant cost of a hydro plant is usually considered as the incremental water rate x the water cost.

I.P.C. (\$/MWh) = water cost (\$/10^6 cu.ft) x I.W.R. (cusecs/MW) x constant (sec/hr x 10^{-6})

$$= \gamma_n \frac{dW_n}{dP_n}$$

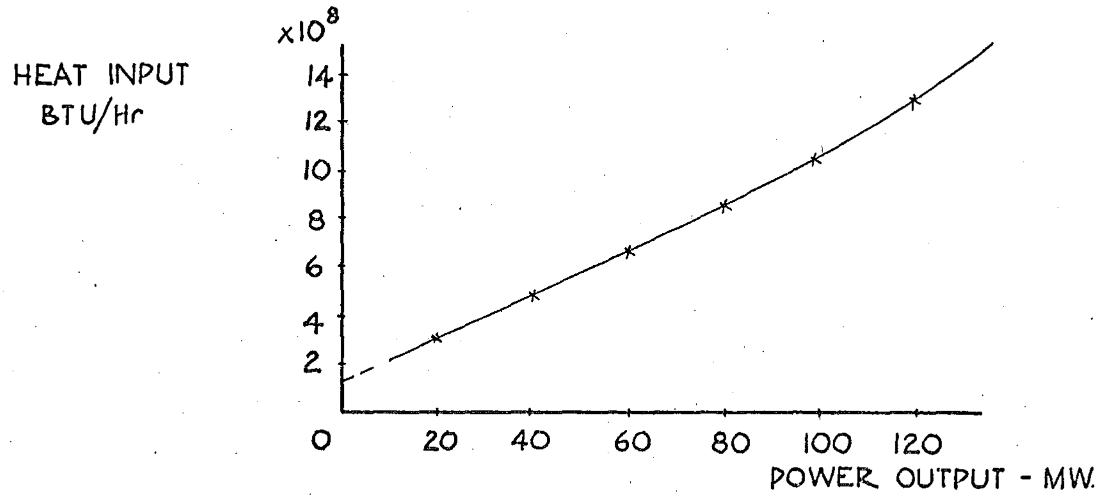

fig. 2·3 INPUT/OUTPUT CURVE

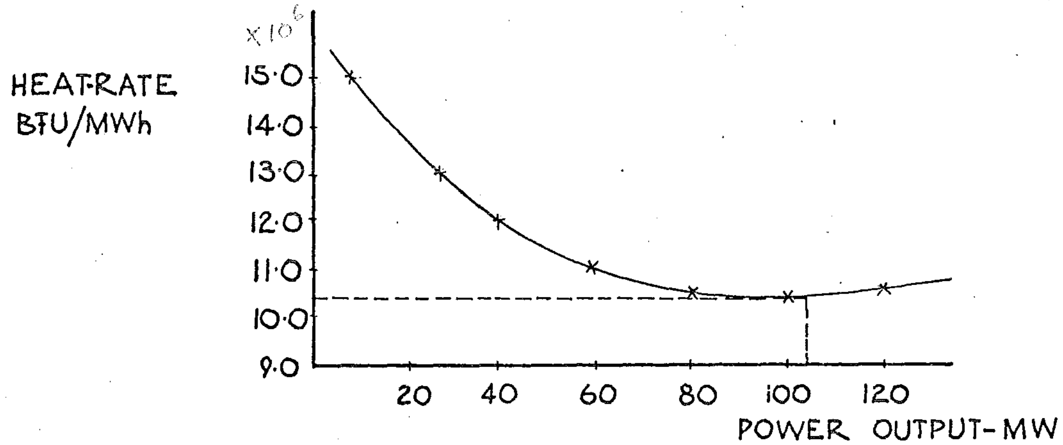

fig. 2·4 HEAT RATE CURVE

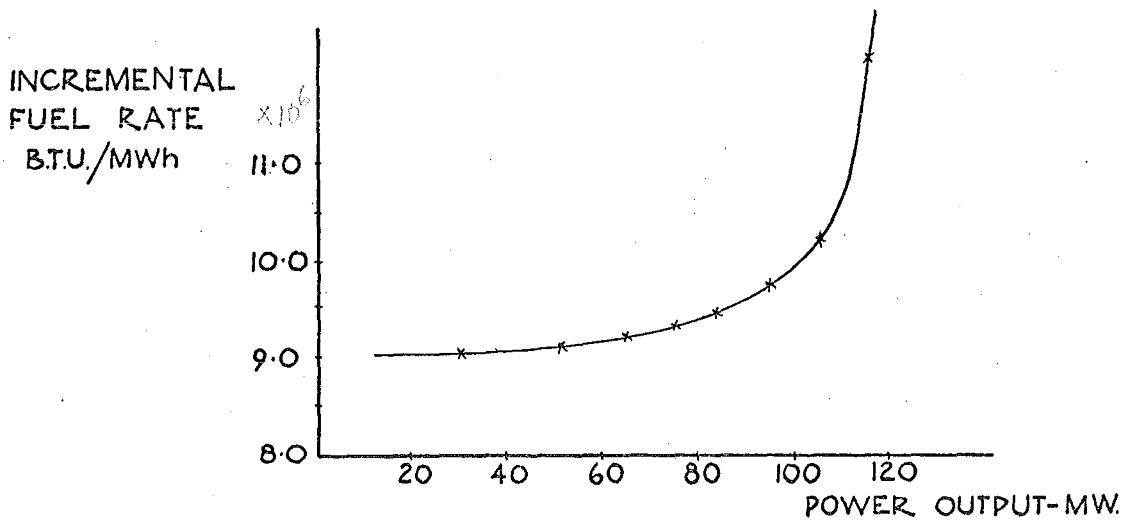

fig. 2·5 INCREMENTAL FUEL RATE

In a manner similar to that shown for thermal plant, the incremental water rate can be represented by -

(i) Step approximation[9]

(ii) Single or multisegment straight-line approximations[10]

and the appropriate form of the hydro co-ordination equation obtained (figure 2.6).

The basic hydraulic characteristics inherent in hydro plant (head, tailwater losses, etc.) alter considerably the shape of the basic curve compared with the equivalent thermal plant.

If the incremental plant costs are considered rigorously, then in calculating the cost component the incremental cost of labour and maintenance should also be included. However, as these costs are often difficult to extract as a function of output, they are normally neglected, or a small arbitrary amount included in the constant term.

2.6 Complete Solution of the Co-ordination Equations

To obtain the economic schedule for a given time period, the co-ordination equations must be solved for each interval within that specified time period, thus in a 24 hourly schedule, they are solved 24 times.

In addition to the constraints already discussed (load demand and water allocation) the individual station generation limits must also be satisfied for each solution of the co-ordination equations.

Therefore -

$$\underline{P_i} \leqslant P_i \qquad \overline{P_i} \leqslant \quad i = 1 \; \ldots\ldots\alpha$$

$$\underline{P_j} \leqslant P_j \qquad \overline{P_j} \leqslant \quad j = \alpha + 1, \; \ldots\ldots\beta$$

where P_i = thermal generation of plant i

P_j = hydro generation of plant j

and $\overline{P_i}$, $\overline{P_j}$, and $\underline{P_i}$, $\underline{P_j}$ are the maximum and minimum limits respectively of P_i and P_j (figure 2.7).

To enable the solution of the equations rearrange them.

From equation (7a) and (8a) -

$$P_i = \frac{1.0 - \frac{f_i}{\lambda} - 2\,\Big(\sum\limits_{\substack{m=1 \\ m \neq i}}^{\alpha} B_{im}\; P_{Sm} + \sum\limits_{n=\alpha+1}^{\beta} B_{in}\; P_{Hn}\Big)}{\frac{F_{ii}}{\lambda} + 2\,B_{ii}} \qquad (10)$$

$$P_j = \frac{1.0 - \gamma_j\,\frac{w_j}{\lambda} - 2\,\Big(\sum\limits_{\substack{n=\alpha+1 \\ n \neq j}}^{\beta} B_{jn}\; P_{Hn} + \sum\limits_{m=1}^{\alpha} B_{jm}\; P_{Sm}\Big)}{\gamma_j\,\frac{W_{jj}}{\lambda} + 2\,B_{jj}} \qquad (11)$$

for thermal and hydro generation respectively. The equations can now be solved iteratively for P_i and P_j. The almost universal method of solving these equations is that of Gauss Seidel iterative method, with γ_j held constant. (The main alternative method for solving the equations is the Newton Raphson method which although clearly superior in speed requires considerably more complicated programming and greater storage capacity.

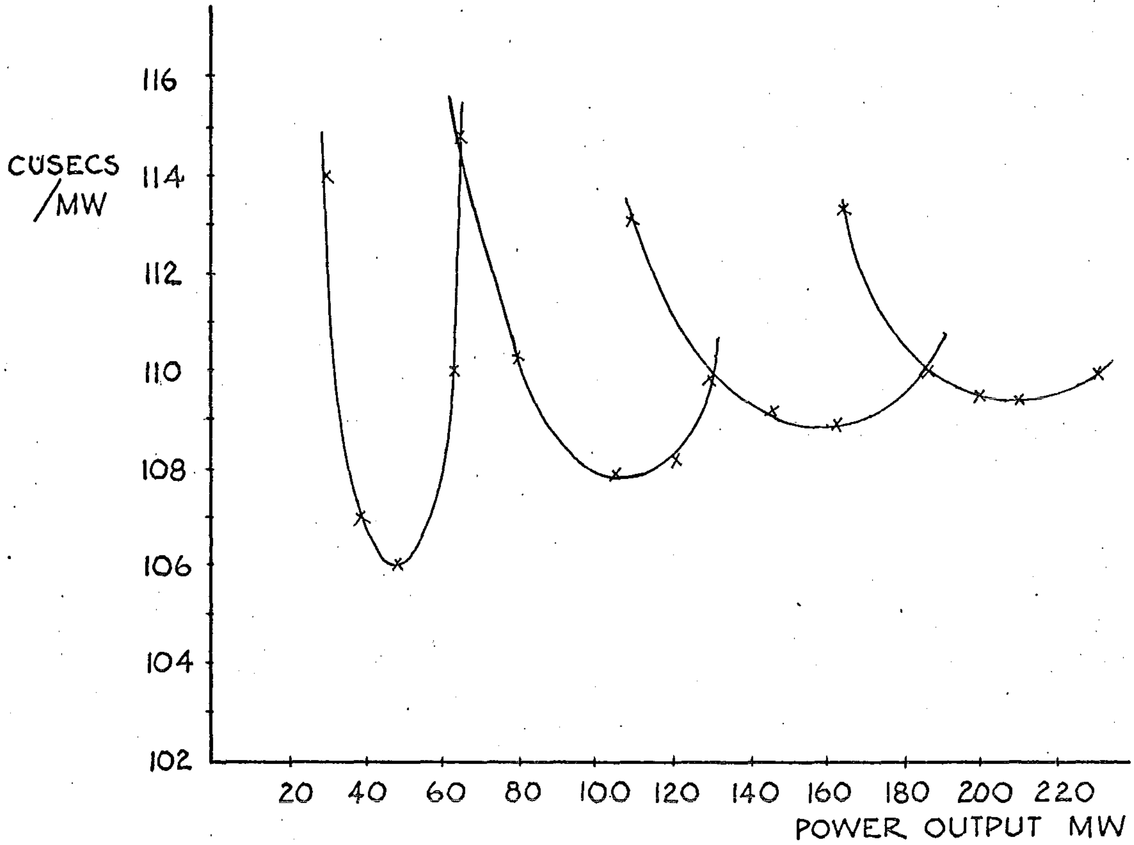

fig. 2·6 INCREMENTAL WATER RATE
(AVIEMORE P.S.)

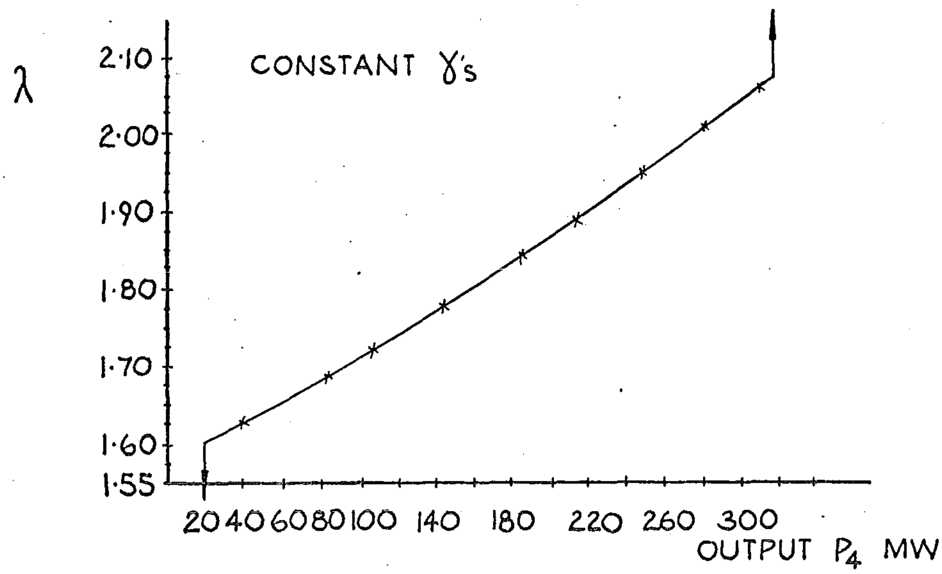

fig. 2·7 EFFECT OF GENERATION LIMITS
(ROXBURGH P.S.)

Therefore discussion has been restricted to the use of the Gauss Seidel method.)

In calculating the station generation, the generation limits must be satisfied. If no restriction is placed on the generation obtained from the solution of the equations, then the equations may yield negative generation, or generation outside the specified generation limits. To satisfy these limits, when such generation values occur, they are replaced by the appropriate limit value, and the equation for that particular station removed from the set of equations.

Further iterations in λ can then proceed in order to satisfy the load demand constraint.

2.6.1 Calculation of λ:

There is a unique value of λ which satisfies the load demand. In solving the equations this value of λ is determined iteratively starting from an estimated value with its corresponding system load, and iterating with new values of λ until the demand is satisfied. Several methods have been used to search for the correct λ value.

(i) Dandeno[10] used a step by step λ increment procedure until successive values of λ produced deviations from the constraint of opposite sign, calculated the midpoint deviation and applied a second order Lagrangian interpolation polynomial to the latter three points, and interpolated for zero deviation. If λ was not correct, he applied an increasing order of polynomial until the correct λ was located. To ensure computational stability, good starting values of λ were required.

(ii) Kirchmayer[3, 11] suggested a linear interpolation having selected two values of λ and calculated the deviation -

$$\lambda^{i} = \lambda^{i-1} + (P_R{}^{d} - P_R{}^{i-1}) \frac{\lambda^{i-1} - \lambda^{i-2}}{P_R{}^{i-1} - P_R{}^{i-2}} \qquad (12)$$

where superscript i = iteration being started

i-1 = iteration just completed

i-2 = preceding iteration

and P_R = received power ($\Sigma P_n - P_L$)

$P_R{}^d$ = power demand required

(Scheduling on total generation can be done equally well (substitute P_T for P_R) and has the advantage that the system transmission losses do not require calculation during the λ iteration.) This linear interpolation is used extensively to calculate the new λ in a number of references and is used in this report.

2.7 Calculation of Base Case Schedule

The above procedures are repeated for each time interval and the schedule obtained for the estimated values of γ's. This first schedule, if the water constraints have not been satisfied, becomes the base case schedule for the correction of the γ's to satisfy the water constraints.

2.7.1 Correction of γ's to meet Water Constraints:

The γ's are the multipliers which are assigned values and determine the amount of water used. If the water constraints are not satisfied at the given plants, then the γ's are modified based on the deviation or residual amount of water (i.e., the difference between the water used and the water allocated). The calculation required to provide the modified values of the γ's takes much longer than that for the value of λ as each time the γ's are changed a complete trial generation schedule must be calculated. An additional complication stems from the fact that the water used at each plant is a function of all γ's and therefore a linear interpolation of γ can not be applied.

The usual approach in calculating the γ's to meet the water constraints is that described in detail by Dandeno[10], which considers the change in water used at each plant for a change in γ at each constrainted plant.

A set of linear simultaneous equations are set up, the number of the equations equalling the number of plant for which there is a specified water allocation. The coefficients of these equations form a Jacobian (or functional determinant) and the equations solved for values of $\delta\gamma$ (the correction for γ) to reduce the deviation to zero.

The linear equations are derived from the Taylor series.

$$f(x + dx) = f(x) + \delta x\ f'(x) + \frac{\delta x^2}{2!}\ f''(x) + \ldots\ldots$$

The Jacobian assumes all stations are independent (the self or diagonal terms) for a change in γ and then corrects for the effects of the existing dependence (the mutual or off-diagonal terms) in assuming -

$$f(x + dx) = f(x) + \delta x\ f'(x)$$

the first order Taylor expansion.

Repeated application of the procedure may be necessary to satisfy the constraints as the coefficients are linear approximations to f'(x). The equations are non-linear in fact since -

(i) the water flow is a quadratic function of the generation

(ii) the generation limits for each time interval may limit the change of generation for a corresponding change in γ resulting in errors in the coefficient calculated.

(iii) The water used at each plant is dependent on all γ's.

As an example, for a system with two constrained hydro plants, the following equation would apply -

$$\frac{\Delta Q_1}{\Delta \gamma_1}\ \delta\gamma_1 + \frac{\Delta Q_1{}^1}{\Delta \gamma_2}\ \delta\gamma_2 = R_1$$

$$\frac{\Delta Q_2}{\Delta \gamma_1}\ \delta\gamma_1 + \frac{\Delta Q_2{}^1}{\Delta \gamma_2}\ \delta\gamma_2 = R_2$$

where -

ΔQ_1	=	(water used at Plant 1 in Base Case (Case 0))	-	(water used at Plant 1 in Case 1)
$\Delta \gamma_1$	=	(γ for Plant 1 in Base Case)	-	(γ for Plant 2 in Case 1)
ΔQ_1^{1}	=	(water used at Plant 1 in Base Case)	-	(water used at Plant 2 in Case 2)
R_1	=	(water used at Plant 1 in Base Case)	-	(water allocated for Plant 1)
ΔQ_2	=	(water used at Plant 2 in Base Case)	-	(water used at Plant 2 in Case 1)
$\Delta \gamma_2$	=	(γ for Plant 2 in Base Case)	-	(γ for Plant 2 in Case 2)
ΔQ_2^{1}	=	(water used at Plant 2 in Base Case)	-	(water used at Plant 2 in Case 2)
R_2	=	(water used at Plant 2 in Base Case)	-	(water allocated for Plant 2)

and BASE CASE = first schedule with estimated γ's

CASE 1 = schedule obtained for γ_1 perturbation

CASE 2 = schedule obtained for γ_2 perturbation

and hence the new values of γ may be calculated -

$$\gamma_{1_{new}} = \gamma_{1_{old}} + \delta\gamma_1$$

$$\gamma_{2_{new}} = \gamma_{2_{old}} + \delta\gamma_2$$

where $\delta\gamma_1$, $\delta\gamma_2$ are the correction factors obtained from the solution of the linear simultaneous equations. With the new γ values a new schedule is calculated and the water used tested for convergence on the allocated water constraints. If these constraints are not satisfied this trial schedule becomes the new Base Case and the procedure is repeated (flow diagram, figure 2.8).

The Jacobian coefficients $\Delta Q/\Delta\gamma$ which are derived from the assumed linear relationship become less accurate the further the initial estimates of γ are from the desired value, because of the effect of the generation limits. To overcome this problem, the γ estimates should ideally be close estimates initially but with a number of γ's required an intelligent guess becomes more difficult, hence several techniques have been developed to prevent breakdown of the procedure if the γ's are not accurately estimated[10, 12]. These techniques will be described in Section 3.

2.8 Summary

An outline of the method of equal incremental costs for the economic generation scheduling in an integrated system has been presented showing -

(a) the basis of the method and its validity for economic scheduling,

(b) its shortcomings, and,

(c) the desirability of including the transmission losses for optimum results.

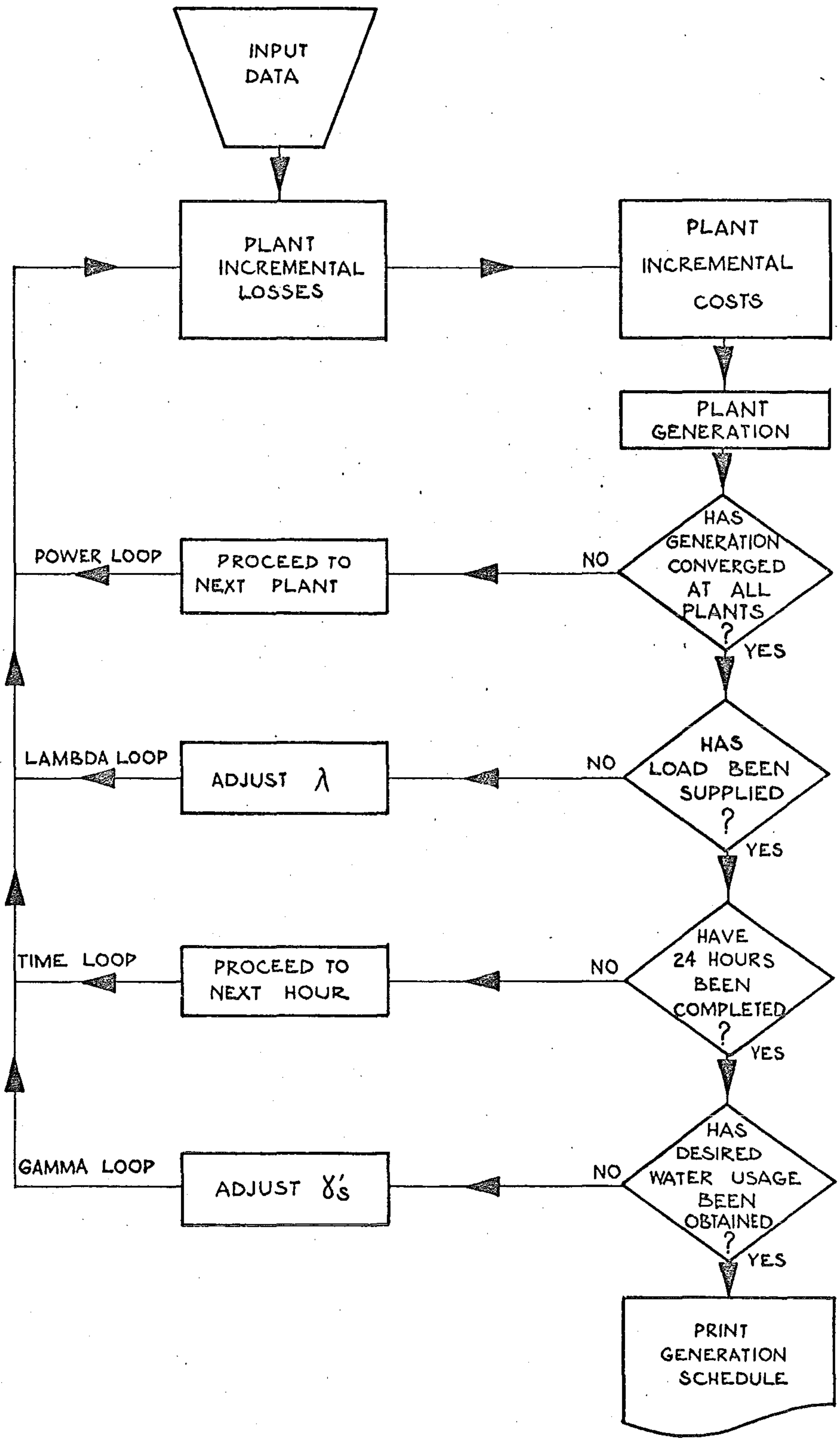

fig. 2·8 FLOW DIAGRAM FOR ECONOMIC SCHEDULING PROGRAMME

SECTION 3

DIGITAL COMPUTER PROGRAM LANZOP

3.1 Introduction

To implement economic load allocation for the New Zealand Power System, in the preparation of this report, a digital computer program (LANZOP) has been developed using the method of co-ordination equations discussed in Section 2 on a model of the South Island System. The program has been written in FORTRAN IV for use on the I.B.M. 360/- series computers.

The aim in the designing of the program and its operation has been to provide a tool for the use of the System Control Operator. The output from the program should satisfy his requirements for information in quantity and quality for effective use. This information required for input should be restricted to essential data, such as the daily load curve, water constraints, and water values which cannot be derived otherwise. As discussed in Section 2, good starting values of water cost (γ) and incremental cost of received power (λ) may reduce the computing time. In the case of λ, the calculation of these values for input as data to the program by the operator will take considerably longer than the calculation of the schedule from poor λ values. If λ estimates are not input, the program has been set up to proceed from fixed λ values. Parameters such as hourly generation limits, plant characteristics which generally have unchanging values are set up with the standard values, but with provision for modification as required. These features have effectively reduced the input quantity and relieved the operator of much detail. Part of the reason for this minimisation of data being done was the likelihood of the program being operated from a remote console, which being a relatively slow speed device is not suitable for extensive data transfer.

3.2 The System Model

The South Island System has been modelled by a six busbar system representing a simplified version of the major transmission lines and their interconnections, with four generation busbars (figure 3.1).

The busbars are referred to as follows:-

Busbar No.	Name	Major Components	Function
1	Waitaki (Basin)	Benmore, Aviemore, Waitaki	Generation, Load
2	Highbank/ Coleridge	Highbank and Coleridge	Generation
3	Cobb	Cobb	Generation, Load
4	Roxburgh	Roxburgh	Generation, Load
5	Livingstone	Livingstone	Switching
6	Islington	Islington	Load

All line impedances have been referred to a common 100 MVA base at 220 kV with modified values to compensate

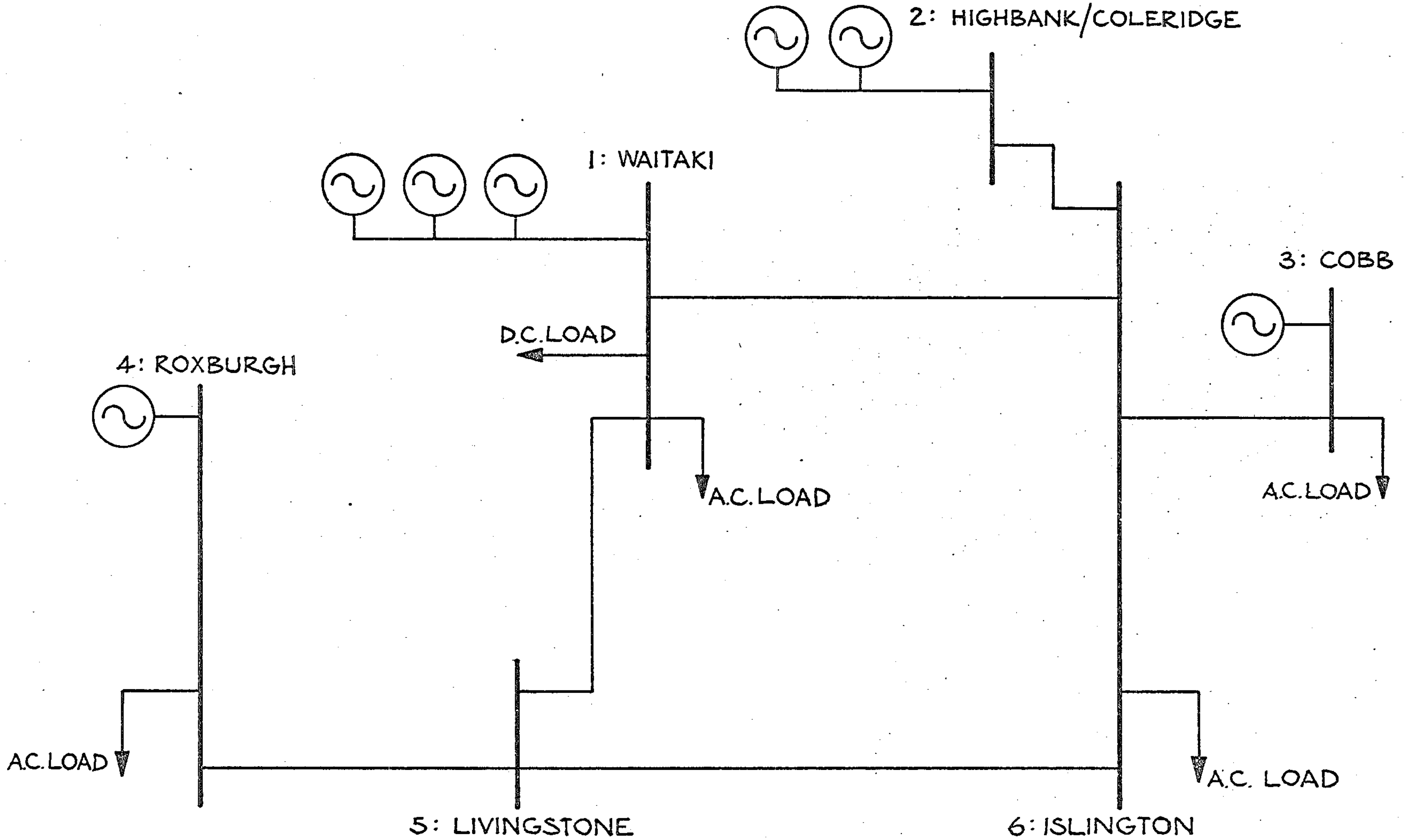

fig 3·1 6 BUS, SYSTEM MODEL

to some extent for lines which are not directly modelled by the system.

The model was chosen to facilitate the development of the computer program for scheduling and to give reasonably accurate results which could be compared with actual schedules obtained from the system. The major simplification was the combining of the Waitaki Basin generation sources into one plant on the Waitaki River. This simplification is valid as the stations are close together electrically and the generation scheduled for each hour would normally be the total output required from the Basin, as the distribution of generation between the individual stations is optimized on a different basis[13, 14] as the stations are considered operationally as a subsystem.

3.3 <u>Transmission Losses</u>

It has been shown that the inclusion of transmission losses results in improved economy. The loss formula method using B coefficients has been used in this program to calculate the incremental and full transmission losses. A computer program LFBCOP[15] (developed previously using Kirchmayer's method[3]) provided the B coefficients required for use in the program LANZOP. The coefficients describe the model of the system as outlined in 3.2 above. For typical results refer to Appendix B.

3.4 <u>Implementation of the Co-ordination Equations</u>

This section will follow closely the sequence of Section 2.6 et seq.

3.4.1 The Organization of Program LANZOP:

The co-ordination equations consist of a set of four equations corresponding to the four generation busbars in the system model, hence the four busbar program.

The flow diagram, figure 2.8, indicates the basic sequence of the generation scheduling program. The program has been organised as a single phase program and during execution, the entire program remains in core storage, requiring approximately 25K bytes of storage of which 3K bytes are needed for data storage. The output information is displayed on a lineprinter while all input is entered from the cardreader. The output data has been kept to a minimum and besides the hourly generation schedule, consists of a check listing only of the load curve, water constraints and water values, and any diagnostic messages for the operator. The program listing and symbol list is contained in Appendix A.

The components of the program are:-

(i) Subprogram BLOCK DATA - this subprogram initializes all the parameters named, with the values defined, setting up the so-called standard values (or options). These values are changed as required by card input. The number of time intervals A (= 24), the plant characteristics WP, WC are typical examples of the parameters initialized with standard values.

(ii) Program MAIN - the control program which defines the sequence of the subroutines and carries out data input and output.

(iii) Subroutine GENALL - the subroutine which calculates the generation schedule.

(iv) Subroutine PAREQ - the subroutine which solves the linear simultaneous equations for $\delta\gamma$ and hence the new values of γ.

(v) Subroutine MINV - the subroutine which inverts the Jacobian matrix as required by PAREQ (Standard I.B.M. Scientific Subroutine).

In addition to these essential program blocks, subroutines have been written which will graph the generation schedule and the individual station schedules on the lineprinter for convenience (subroutines PLOTG and GRAPH), but as they are very time consuming due to the relatively slow speed of the lineprinter, they are normally omitted and therefore no further reference will be made to them.

3.4.2 Data Input -

The minimum data required for successful execution of the program is:-

(i) Daily load curve

(ii) Estimated water values (γ)

(iii) Specified water constraints (water allocation)

In addition, (iv), any nonstandard values for initialized parameters, and good starting values of λ may be necessary or desirable.

A number of data checks are made to prevent incorrect data being used. The generation limits, if input, are checked for validity against standard values and the water constraints for feasibility, based on the specified generation limits, and if necessary are reset to the appropriate limit.

3.5 Calculation of the Generation Schedule

The flow diagram for the calculation is shown in figure 3.2.

3.5.1 Calculation of Plant Generation:

The co-ordination equation for each plant is solved by the Gauss Seidel iterative method[16] in the form -

$$P_n = \frac{1.0 - \gamma_n \dfrac{W_n}{\lambda} - 2 \displaystyle\sum_{\substack{m=1 \\ m \neq n}}^{n} B_{mn} P_n}{\gamma_n \dfrac{W_{nn}}{\lambda} + 2B_{nn}}$$

where P_n = generation for hydro plant n

since direct solution is not possible. Computational experience has shown that the inclusion of the incremental transmission losses and hence the B_{nn} term in the scheduling equation, results in a computationally more stable system, and the equations always converged. Comparative schedules were made neglecting the losses and considerable difficulties arose in attempting to converge on the specified water usage, and in several cases convergence was not achieved.

The Gauss Seidel iterative technique is often improved by the use of acceleration factors (also known as convergence factors) when solving simultaneous equations. In a large number of systems these factors have been used and reduce

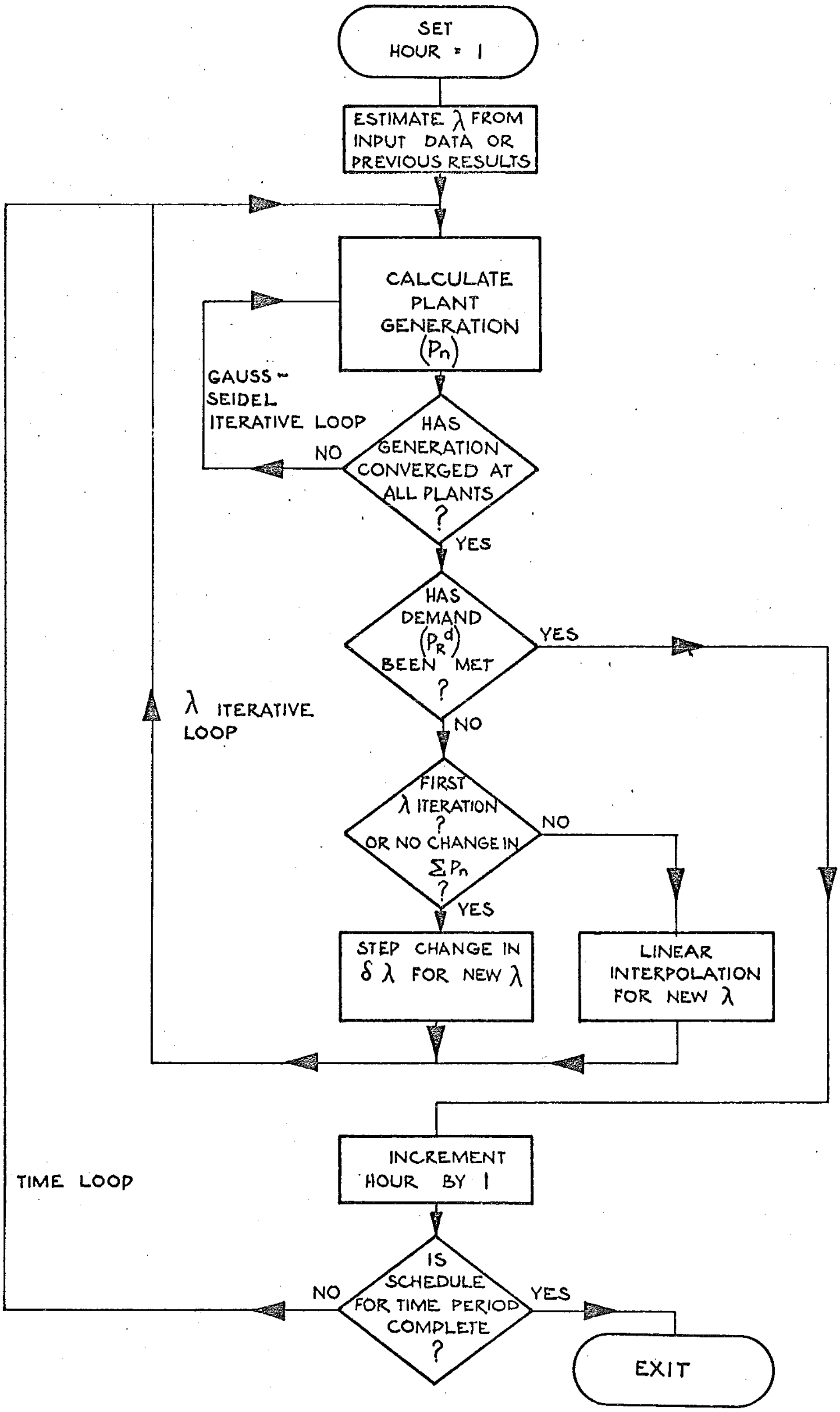

fig. 3·2 GENERATION SCHEDULE FLOW DIAGRAM.
SUBROUTINE GENALL P_n & λ ITERATIVE LOOPS,
& CALCULATION OF COMPLETE SCHEDULE OVER SPECIFIED TIME PERIOD

computation time significantly[17]. The successive values of P_n are modified thus -

$$P_n^{i-1} = P_n^{i-2} + (P_n^{i-1} - P_n^{i-2}) \times \text{acceleration factor}$$

where i-1 = iteration just completed, etc.

Typical values of acceleration factor are 0.3-0.6. For this application, extensive testing of the Gauss Seidel iteration was carried out with varying acceleration factors, the result of which showed that in this system, the use of an acceleration factor <u>increased</u> the number of iterations required for convergence, by causing oscillation of the convergence trajectory.

Typically -

the number of iterations required without acceleration = 5
the number of iterations required with acceleration = 10
(Acceleration factor = 0.35)
where e = tolerance = 0.005%

See figure 3.3.

To initialize the Gauss Seidel solution, the initial values of P_n have been set to $\underline{P_n}$. In practice, these limits were often exceeded during the first few iterations. If the limiting values were substituted immediately and the number of equations reduced then a solution in which the true value of P_n was just inside the limit was often excluded. Although the simultaneous equations were apparently satisfied, convergence on the system load demand could not be achieved in the cases where the true value of generation happened to coincide with the value required for convergence. To overcome this serious problem, the limit substitution was made, but the equation left in solution for the first and second iterations.

An earlier method of handling the generation constraints in the Gauss Seidel iteration, by substituting any limit values only after the first iteration had been completed, proved most unsatisfactory. The apparent solution induced oscillation in later iterative loops and convergence on the System load demand became unattainable since an iterative "limit cycle" resulted. See figure 3.4. This condition was accentuated by the use of a linear interpolation formula for λ. (Reference Section 3.5.2.)

3.5.2 Calculation of λ:

Convergence having been achieved for the solution of the generation values P_n, the total generation, the transmission losses, and hence the received power P_R were calculated for the current value of λ, i.e.,

$$P_R = \Sigma P_n - P_L$$

At this point, the solution is tested for the satisfying of the System load demand $P_R{}^d$, i.e.,

$$\text{Is } P_R = P_R{}^d \pm e \text{ ?}$$

where e = tolerance specified

If this is not satisfied then iteration of λ proceeds (with the consequent recalculation of the generations) until the demand is satisfied.

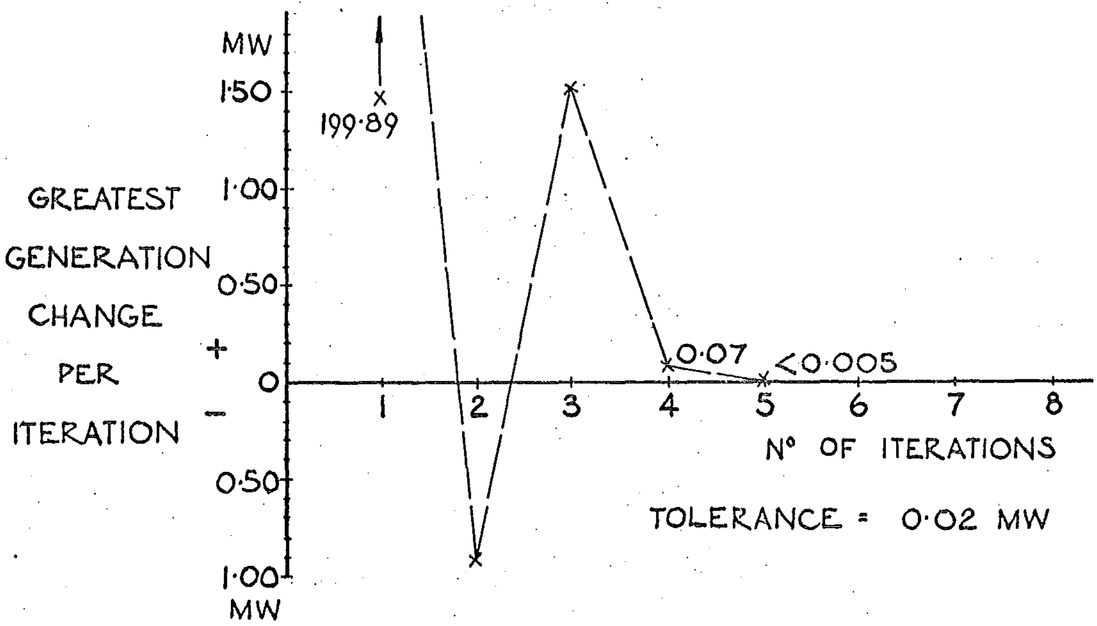

fig. 3·3 TYPICAL CONVERGANCE TRAJECTORY (NO ACCELERATION)

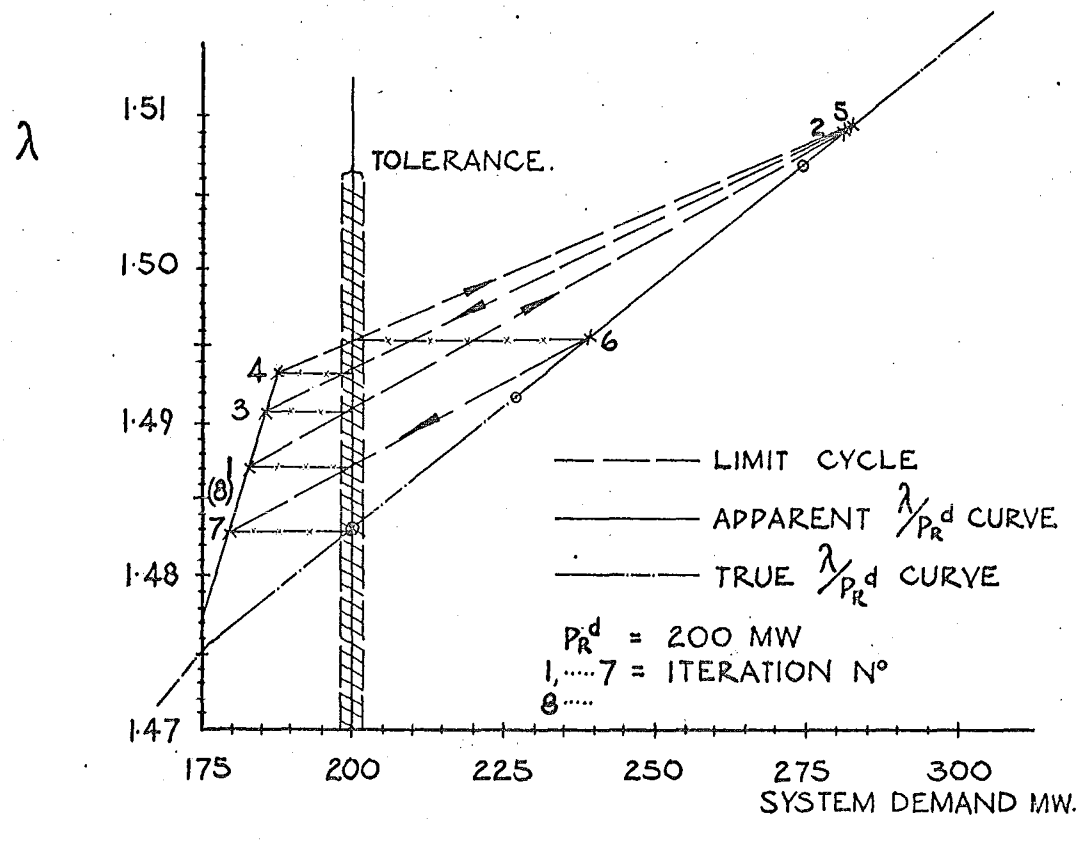

fig. 3·4 LIMIT CYCLE RESULTING FROM INCORRECT CONSTRAINT HANDLING

From the results of a large number of schedules it was shown that an estimated λ value close to the true value of λ which satisfied the demand, significantly reduced the convergence time. Consequently in the selection of λ's for the perturbation schedules (i.e., the schedules calculated in deriving $\Delta Q/\Delta\gamma$) and the new base case schedule, the results of previous iterations and the change in γ(s) have been used to make closer estimates of λ for the trial schedules. To date, the effectiveness of the estimating technique is somewhat limited if the values of γ are significantly different from the average values used, as the numerical constants used in the estimation have been derived from analysis of previous experimental results and are not dynamically updated.

To aid convergence, a set of λ values are calculated to act as reference points. These reference points are the calculated λ values at which the plant generation limits are imposed and are defined by -

$$\lambda_n = \frac{\gamma_n \times (W_{nn} \times P_n + W_n)}{1-2 \sum_m B_{mn} P_m}$$

for example, refer figure 3.5.

From this definition a set of guide points is found. $\overline{\lambda}_n$ and $\underline{\lambda_n}$ for $P_n = \overline{P}_n$ and $P_n = \underline{P_n}$ respectively

where $\overline{\lambda}_n$ = maximum value of λ for maximum generation $\overline{P}_n$ at plant n

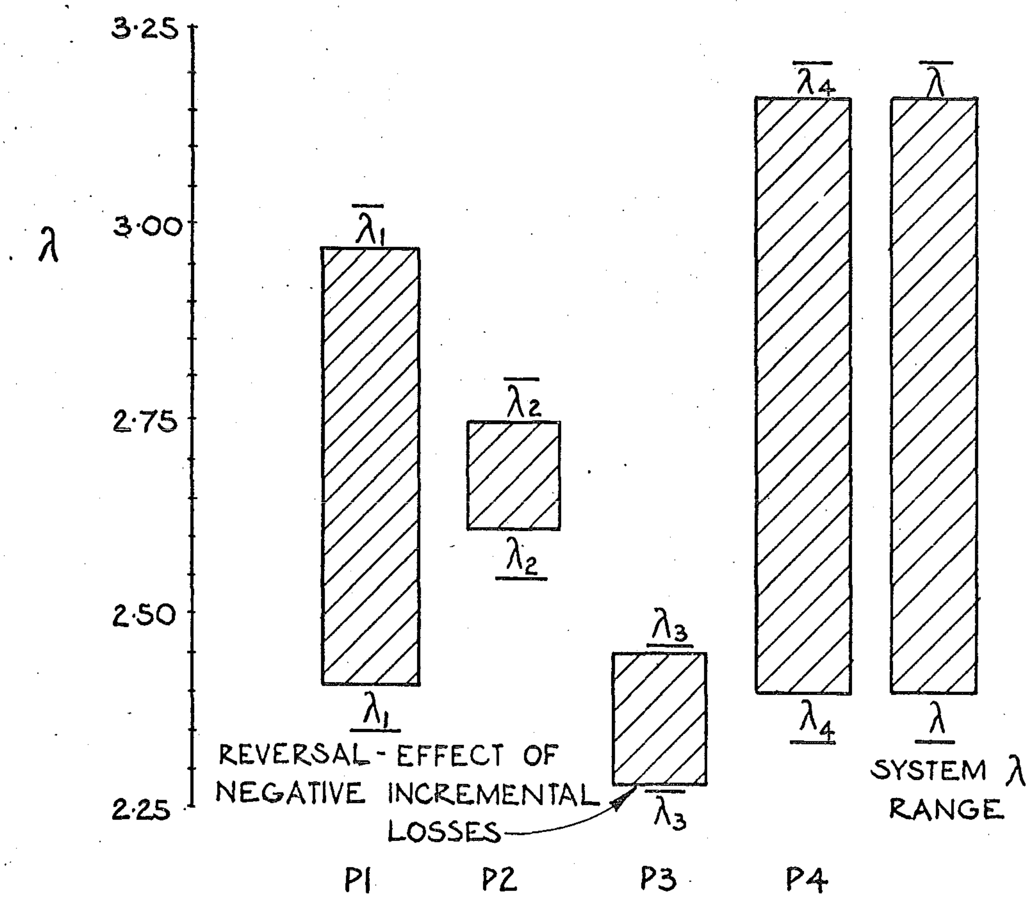

fig. 3·5 λ REFERENCE POINTS

$\underline{\lambda}_n$ = minimum value of λ for minimum generation $\underline{P}_n$ at plant n and then obtain $\bar{\lambda}$ and $\underline{\lambda}$ being the maximum $\bar{\lambda}_n$ and minimum $\underline{\lambda}_n$ respectively to define the expected range of λ.

Procedure for Convergence on Demand -

(i) Estimated value of λ input as data.

The plant generation outputs for this value of λ are calculated and from the deviation $(P_R - P_R^d)$ a step change of λ is made in the correct direction.

$$\lambda' = \lambda^{est} + \Delta\lambda$$

where $\Delta\lambda$ = Const x λ^{est} x SGN $(P_R^d - P_R)$

and SGN $(P_R^d - P_R)$ = +1 $\quad P_R^d > P_R$

= 0 $\quad P_R^d = P_R$

= -1 $\quad P_R^d < P_R$

and a new trial schedule obtained. If the power received (P_R) has changed then the linear interpolation formula (equation 12, Section 2) is applied. This interpolation is repeated until $\left| P_R^d - P_R \right| \leqslant e$

where e = specified tolerance.

(ii) Estimated value of λ not input as data.

The trial schedule for $\underline{\lambda}$ is calculated and then iteration proceeds as in (i) above.

A number of factors may make this procedure unsatisfactory:-

(a) Demand outside range of generation -

$$\text{i.e.,} \quad \sum \bar{P}_n < P_R^d \quad \text{or} \quad \sum \underline{P}_n > P_R^d$$

This prevents convergence. This condition is assumed if λ has not altered between two successive iterations and has a value $\lambda = \underline{\lambda}$ or $\lambda = \overline{\lambda}$ for both iterations, and the program terminates on this occurrence. Since this is an unlikely condition it is not tested for directly during the data check.

(b) Slow Convergence -

This can occur if there is a large disparity between λ reference points with no change in generation (see figure 3.6) and the deviation is small (just greater than e) with a consequently small $\Delta\lambda$. In this event, the program searches for the next significant λ reference point and proceeds. Convergence is then normally achieved within several further iterations.

(c) Solution of the Simultaneous Equations resulting in negative γ's -

The λ reference points for some plant become inverted and the λ iteration breaks down. In this event, the γ's are tested and reset to the equivalent of 5% change and the plant output schedule (trial schedule) recalculated.

3.5.3 Calculation and Adjustment of γ (Gamma):

As outlined in Section 2, the γ values (water values) determine the water used at each hydro plant. If after the first schedule has been calculated the correct amount of water has not been used, then the γ's at the plants constrained must be modified. The method used in this program to modify the γ's is that used by Dandeno[10] using linear simultaneous equations to obtain the $\delta\gamma$'s, and

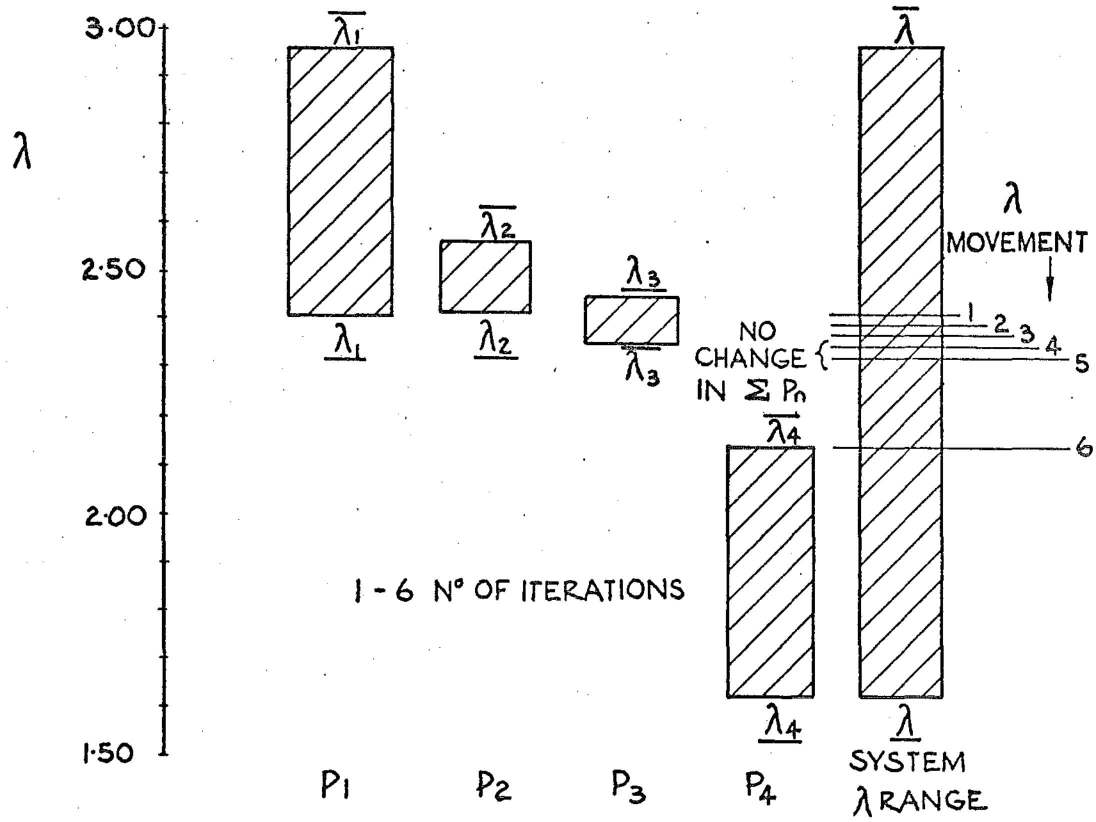

fig. 3·6 USE OF λ REFERENCE POINTS

calculating trial schedules for each perturbed γ to obtain the $\Delta Q/\Delta\gamma$ elements of the Jacobian (relaxation method).

The flow diagram showing the program sequence is shown in figure 3.7.

The relaxation method is satisfactory as it stands, provided adequate starting values of γ are available, and the specified water constraints are realistic. Where these constraints are not realistic due to generation or load constraints, the method can result in oscillation about, or divergence from, the solution closest to the non-realistic solution specified originally. (Note: this realistic solution will be described as the "Best Fit" solution in later references.)

To overcome this instability, Dandeno[10] suggested calculating a number of trial schedules to provide satisfactory starting values for γ while Drake, Kirchmayer et al.[12] suggest limiting any change in γ between schedules to a maximum of 5%. These methods slow the rate of convergence but generally ensure convergence if it is possible. The figure of 5% maximum change has proved to be a useful guide and has been used for corrective methods when required.

In developing LANZOP, a standard set of γ values have been used as the starting values regardless of the water constraints specified so that the techniques developed would not be dependent on the need for good initial estimates to achieve the required water constraints. This policy has been successful and provided the initial γ values are not

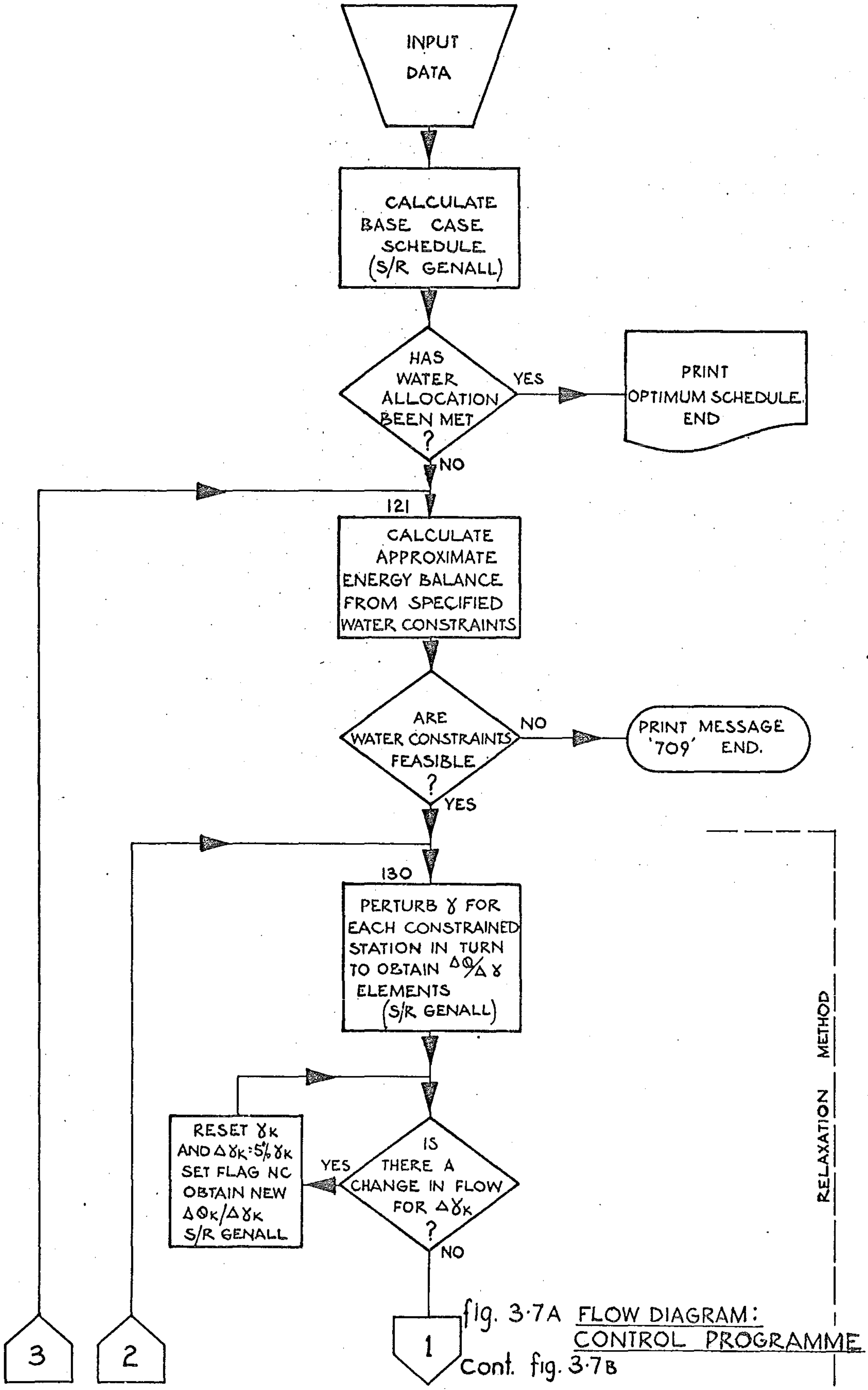

fig. 3·7A FLOW DIAGRAM: CONTROL PROGRAMME

Cont. fig. 3·7B

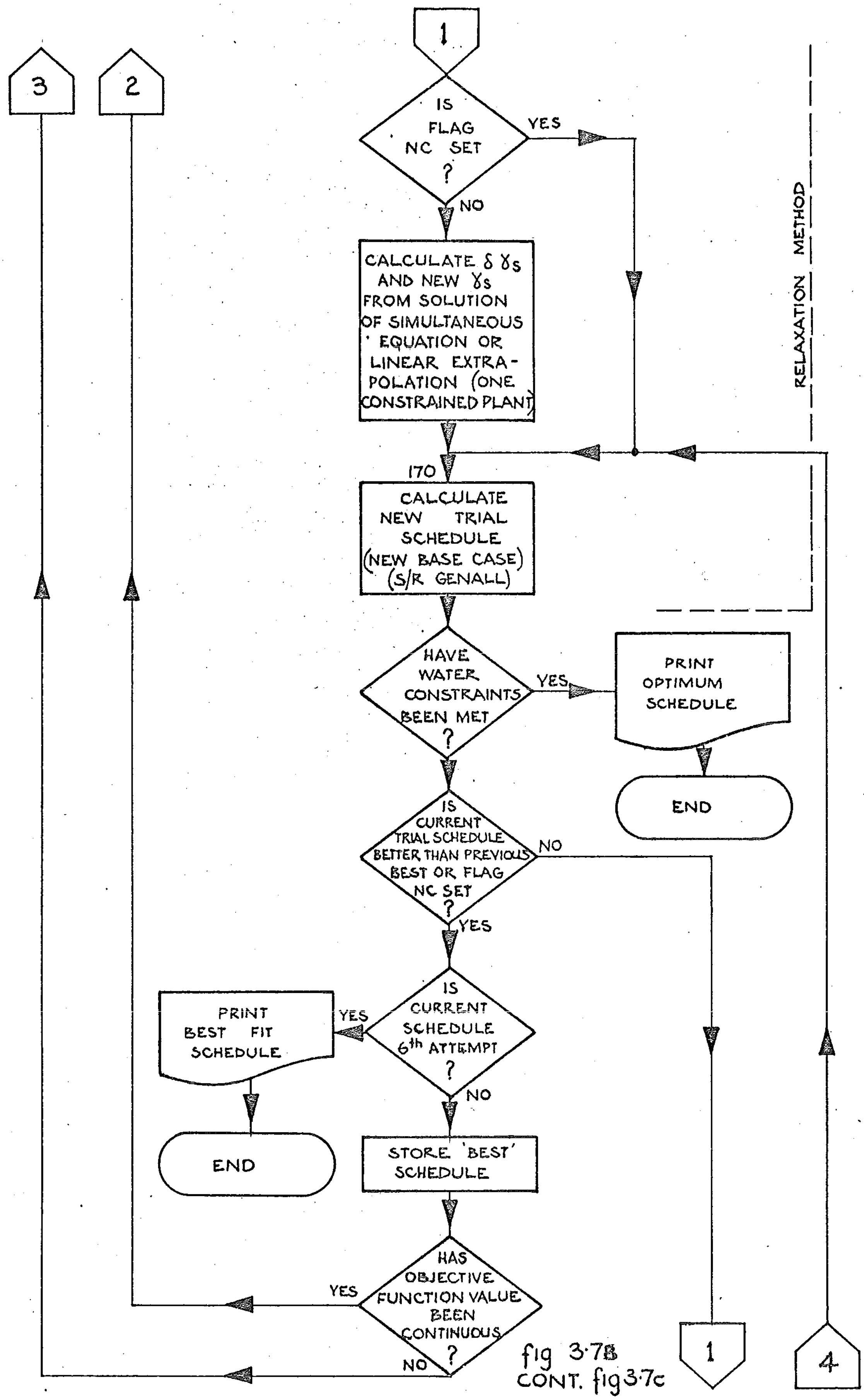

fig 3·7B
CONT. fig 3·7c

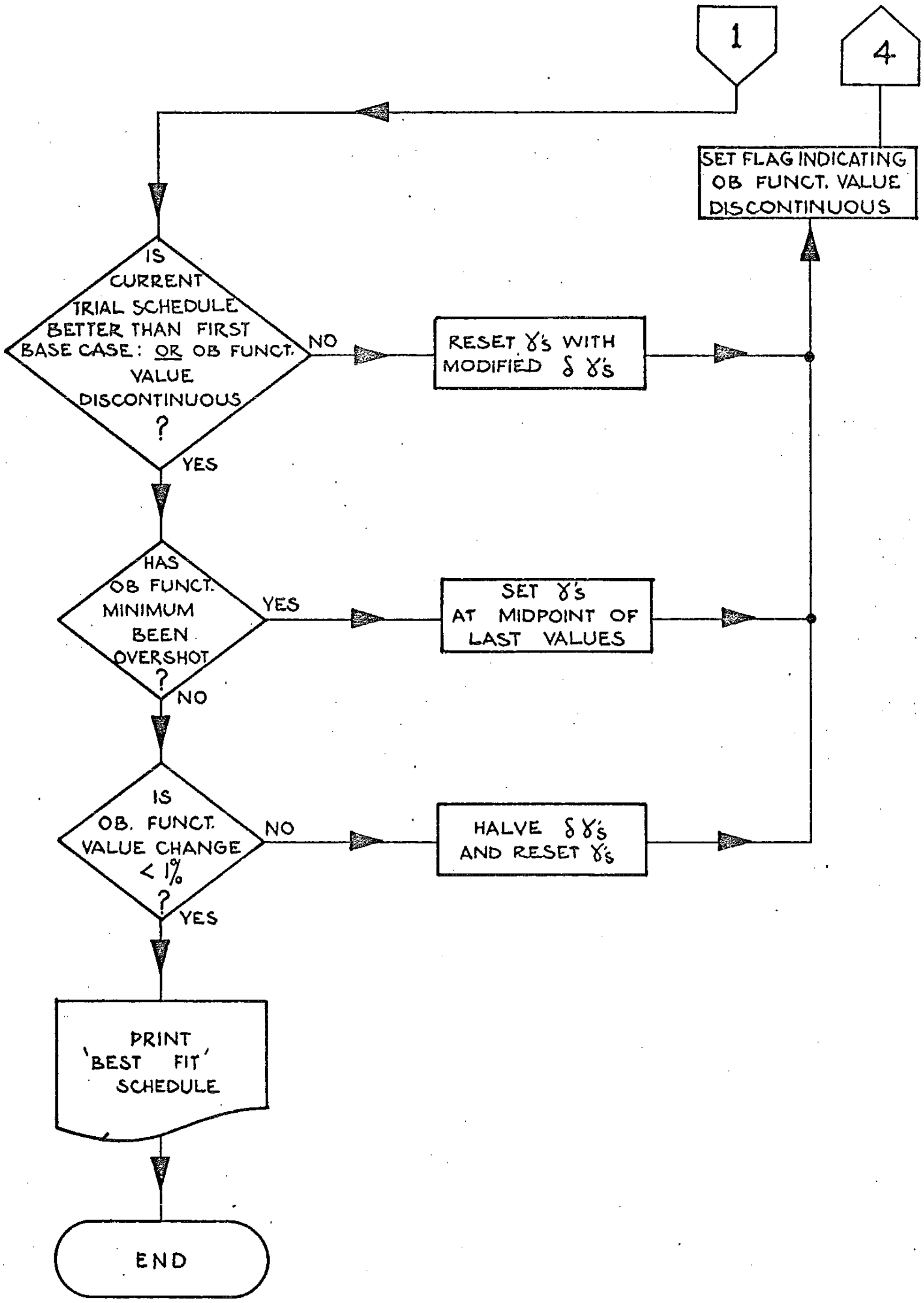

fig. 3·7c FLOW DIAGRAM CONTROL PROGRAMME too inaccurate (50-100% error, say), the program will obtain a solution satisfying the constraints if these constraints are realistic. Where the constraints cannot be satisfied and a "Best Fit" solution only is possible, the result of this policy is that the first "Best Fit" solution obtained may be improved to some extent by reassessment of the water values.

The technique used to achieve this, makes use of an objective function which describe the "goodness" of any given schedule in a single value, and the control of the program sequence when instability or divergence occurs is based on the current and previous values of the objective function.

The Calculation of $\Delta Q_n / \Delta \gamma_n$ -

The change in γ_n used for calculating the perturbation schedules for the $\Delta Q_n/\Delta\gamma_n$ is important as it effects the accuracy of the gradient ($\Delta Q/\Delta\gamma$) as the flow (Q)/water value (γ) curve is nonlinear (figure 3.8) due to the generation constraints. Not only does the magnitude of $\Delta\gamma_n$ alter the gradient but also the γ_n value itself. Because the correct water usage cannot be obtained by linear interpolation of γ_n's in the calculation of $\Delta Q_n/\Delta\gamma_n$, the magnitude of $\Delta\gamma_n$ is limited to a maximum of 5% of γ_n, if the adjustment defined by the deviation R_n (refer section 2.7.1) would normally exceed this figure.

The Calculation and Use of the Objective Function -

The major difficulty in using a single valued objective

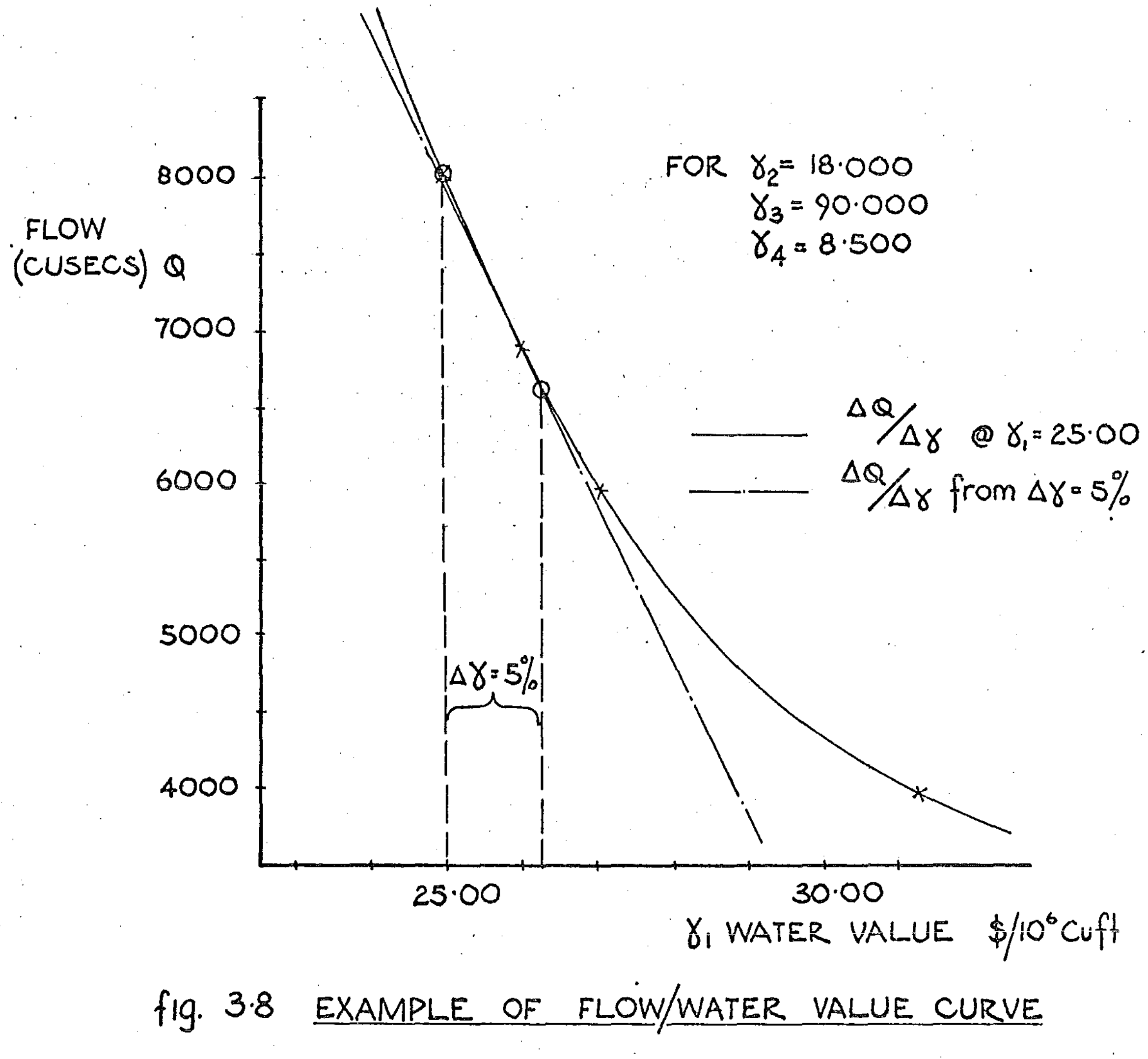

fig. 3·8 EXAMPLE OF FLOW/WATER VALUE CURVE function is that the individual plant deviations may be swamped by a dominant deviation, if this occurs. An objective function has been used which attempts to indicate the relativity of each plant constrained, and takes into account the wide range of incremental water rates for each plant.

$$\text{Objective function Value (OB value)} = \sum_{j=1}^{k} \left(\frac{Q_j - Q_j^d}{Q_j^d \times p} \times 100 \right)^2$$

where k = the number of constrained stations

Q_j = water used at plant j

Q_j^d = specified water constraint for plant j

p = % tolerance on water constraint convergence (normally 1%, $p = 1$)

This objective function has proved quite satisfactory. The objective function value has been used to control the program sequence once the errors from the linear approximations cause instability. The ideal convergence trajectory is shown in figure 3.9 as a "continuous" curve. Where the water constraints are easily attainable, and good γ starting values are input, the objective function value follows the general shape of this curve closely and convergence is achieved in minimal computing time.

However, when there is conflict between the requirements of the system load demand in the form of generation limits, and the water constraints, the $\Delta Q/\Delta\gamma$ values become inaccurate and hence the $\delta\gamma$'s (the γ correction factors) become inaccurate causing instability.

When this occurs the objective function is tested and the appropriate action taken as follows (refer also to figure 3.7):-

(i) Continuously decreasing OB value (figure 3.9):

- no interruption to γ iterative procedure
- $\delta\gamma$'s unmodified.

(ii) Discontinuous OB value (figure 3.10):

- γ iterative procedure interrupted (current OB value $>$ previous OB value)
- $\delta\gamma$'s reset to half previous value and trial schedule calculated (figure 3.11). This reset procedure is repeated until -
  - (a) new OB value obtained $<$ previous minimum OB value, then standard γ iteration restarted.
  - (b) change in OB value $<$ 1%, then search terminated and schedule with minimum OB value output as "Best Fit" schedule.

(iii) Discontinuous OB value with Saddle Point (figures 3.12 and 3.13):

- γ iterative procedure interrupted
- $\delta\gamma$ reset as in (ii) above and trial schedule calculated; this is repeated as above until OB value increases indicating an apparent minimum has been overshot.
- $\delta\gamma$'s reset to midpoint of last two values and trial schedule calculated and sequence continues as for (ii) above.

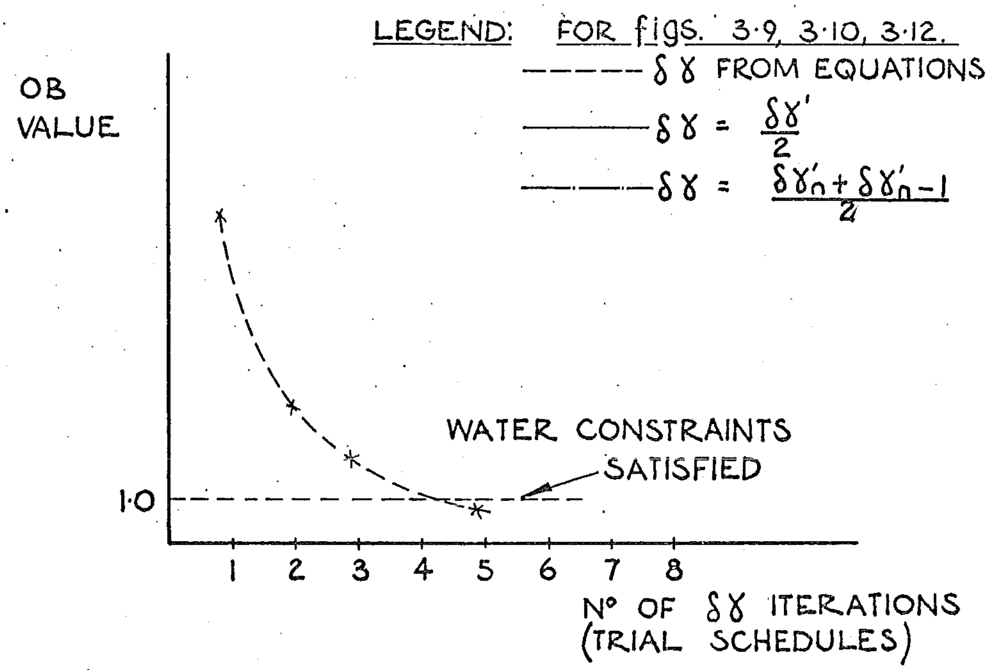

fig. 3·9 CONTINUOUS OBJECTIVE FUNCTION

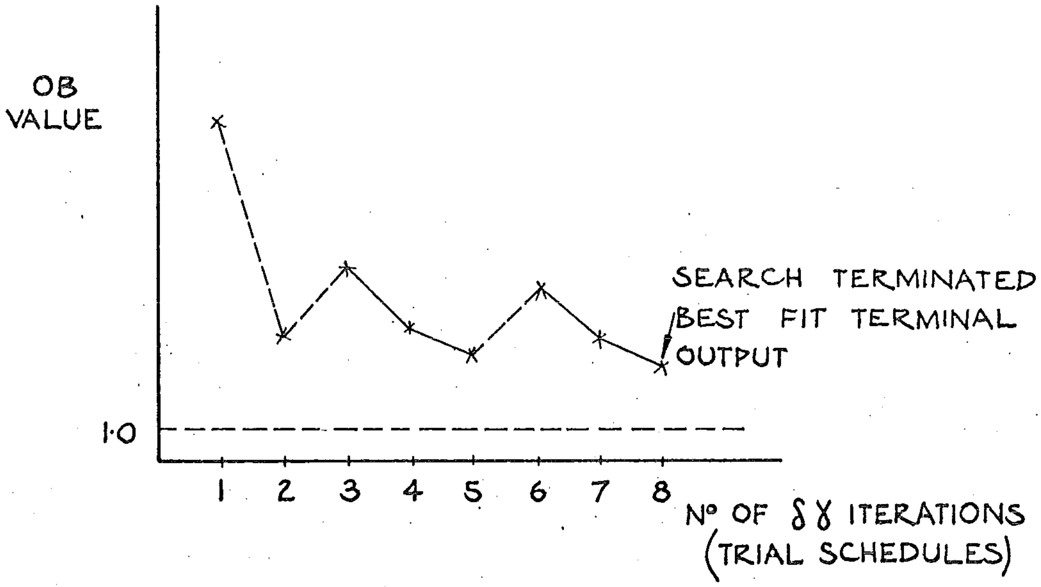

fig. 3·10 DISCONTINUOUS OBJECTIVE FUNCTION

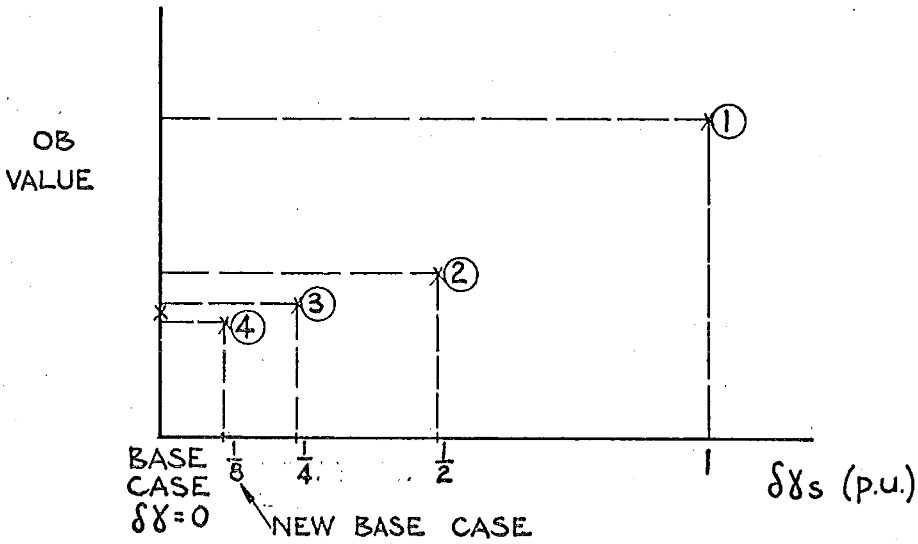

fig. 3·11 DISCONTINUOUS OBJECTIVE FUNCTION

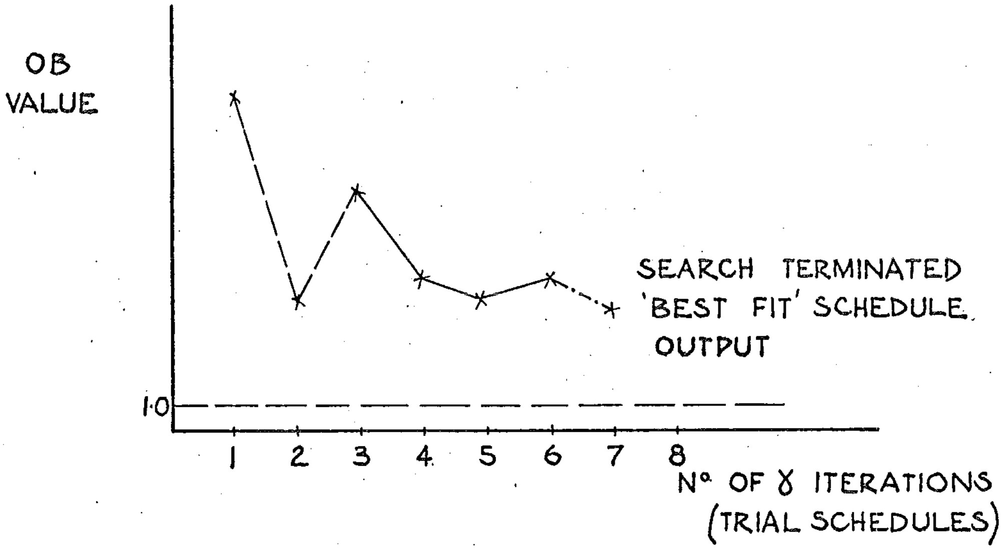

fig. 3·12 DISCONTINUOUS OBJECTIVE FUNCTION (WITH SADDLE POINT)

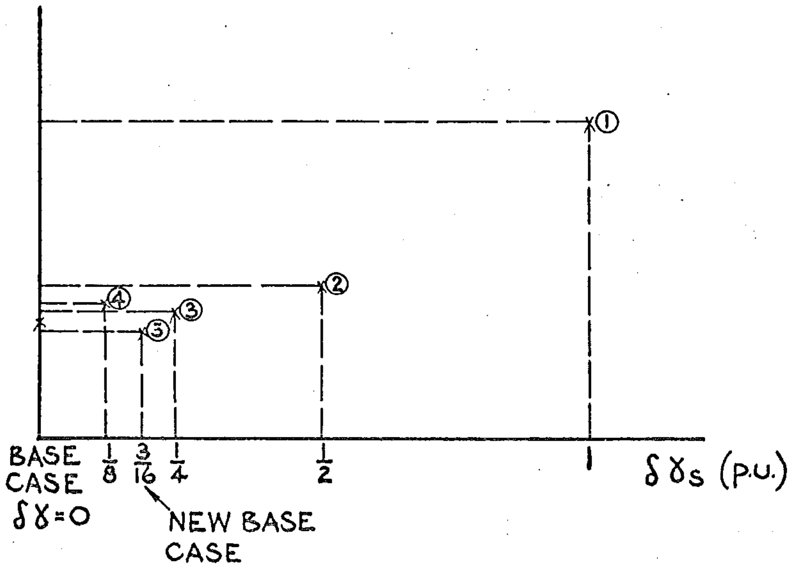

fig. 3·13 DISCONTINUOUS OBJECTIVE FUNCTION (WITH SADDLE POINT)

1 - γ ITERATION NUMBER

The search for the minimum value if the water constraints cannot be satisfied is terminated if improvement in trial schedules is less than 1% or six attempts at convergence have been made through the full γ iterative cycle. The control of the program by the objective function value ensures termination of the program at some point, whereas previously in this conflicting situation, the search procedure hunted between a number of close solutions with no criterion available for its termination.

3.5.4 The Co-ordination of the Convergence Tolerances:

The co-ordination of the convergence tolerances is important since a number of nested loops are used in obtaining the generation schedule.

The most critical loop is that of the γ loop. In order to obtain coefficient values for the Jacobian which are consistent, the slack introduced by the tolerance in the λ (demand) loop must be small. As the γ loop is the outermost loop, the relative tolerances must be progressively reduced for the inner loops.

The following tolerances have been used and give consistent results without excessive computing time being required:-

(i) Gauss Seidel Tolerance $e_{P_n} = TC \times P_n \times 0.005$

(ii) Load Demand Tolerance $e_{\lambda} = TC \times P_R{}^d \times 0.01$

where P_n = output plant n

$P_R{}^d$ = load demand

TC = tolerance constant

standard value = 0.01

This tolerance constant gives for example:-

$$e_{p_n} = 0.02 \text{ (MW) @ } P_1 = 400 \text{ MW}$$

$$e_{\lambda} = 0.06 \quad \text{@ } P_R^{\,d} = 600 \text{ MW say}$$

The maximum water usage variation implied is then $\pm$ 5 cusecs $\ll$ 1% when calculating the Jacobian coefficients $\Delta Q/\Delta \gamma$ ensuring negligible error due to iterative errors.

3.6 Spinning Reserve

As an aid to the system operator, the amount of spinning reserve on line is calculated and output for each time interval. It is approximate only, since the distribution of generation amongst the individual machines at the lumped busbars (e.g., Waitaki) as unknown and this generation is scheduled as a suboptimum.

3.7 Performance of the Program

Minimal optimization of the actual programming has been done, and some improvement may be expected, if this is carried out.

3.7.1 Performance Times (typical 4 busbars 24 hour schedule):

	I.B.M. 360/44 PS	I.B.M. 360/40
Compile (from card)	2mins 30 secs	3 mins
(Link Edit)	-	30 secs
(Loader)	10 secs	-
Execute	30 secs	35 secs

If the program is in module form these times are reduced significantly, and the time to input from card is reduced to 1 minute before execution.

3.7.2 Extension Capability of the Program:

The innermost loop of the program is the Gauss Seidel solution for the generations (P_n's). In this method of solution:

(i) the time per iteration is proportional to N = number of busbars,

(ii) the number of iterations $\propto N$, and,

(iii) the total calculation time $\propto N^2$.

Consequently increasing the number of generation busbars increases the maximum computing time for each schedule ($\propto N^2$). The iteration time for the HOUR (time) loop is proportional to t = number of time intervals and the γ loop proportional to K, where K = number of constrained stations. However, since the terms in the co-ordination equations which are independent of the other plant (B_{nn}) are the dominant ones, and the generation limits often reduce the number of equations to be solved, it is expected that the extension of the program will not increase as much as predicted theoretically.

The extension of the program is limited only by the maximum acceptable running time, and possibly the program storage requirements. (As a comparison: Southern California Edison System[12] - 7 hydro, 2 thermal - 2-3 minutes for 24 hour schedule I.B.M. 7090 programmed in FORTRAN.)

The techniques used in the program have enabled all hydro plant to be constrained if required, provided the Base case schedule and the schedule implied by the specified water constraints, have equivalent energy requirements.

3.8 Schedule Diagnostics

To assist the System Control Operator in reassessing constraints or water values, or when data errors are detected a number of messages are output when results require it.

Typical examples of these are shown in the sample results in Section 4 (figures 4.5-4.8).

3.9 Summary

The features and techniques used in program LANZOP solving the co-ordination equations for the optimum load allocation, including the transmission losses have been presented, together with a description of the system model to which the program has been applied. Several points considered in the basic theory have not been implemented due to the limited time available for the developmental work in the preparation of this report.

SECTION 4

RESULTS, CONCLUSIONS AND RECOMMENDATIONS

4.1 Accuracy of the Schedule

The accuracy of the results is dependent upon the accuracy of the input data, since the magnitude of the computational errors is much less than that of the input data.

4.1.1 Load Demand Forecast:

The error in the forecast load demand depends upon the method of forecasting used, and the climatic conditions prevailing at the time of the forecast. The accuracy of the average load forecast, over 24 hours is usually within 10%, with a minimum error of 4-5% being possible under favourable conditions.

4.1.2 Plant Data:

The Plant Data (incremental water rate) used in the economic scheduling program are 2% accurate on average for most cases, with an outside limit of 5-6%, on the information available. The incremental water rate is calculated from, either the efficiency test results on plant, or, more usually from the manufacturer's tender documents and the expected operating conditions for the plant. The actual plant characteristics may be considerably different from characteristics quoted in the tender, consequently the single line approximation used (figure 4.1) is sufficiently accurate under these circumstances, as it is doubtful whether

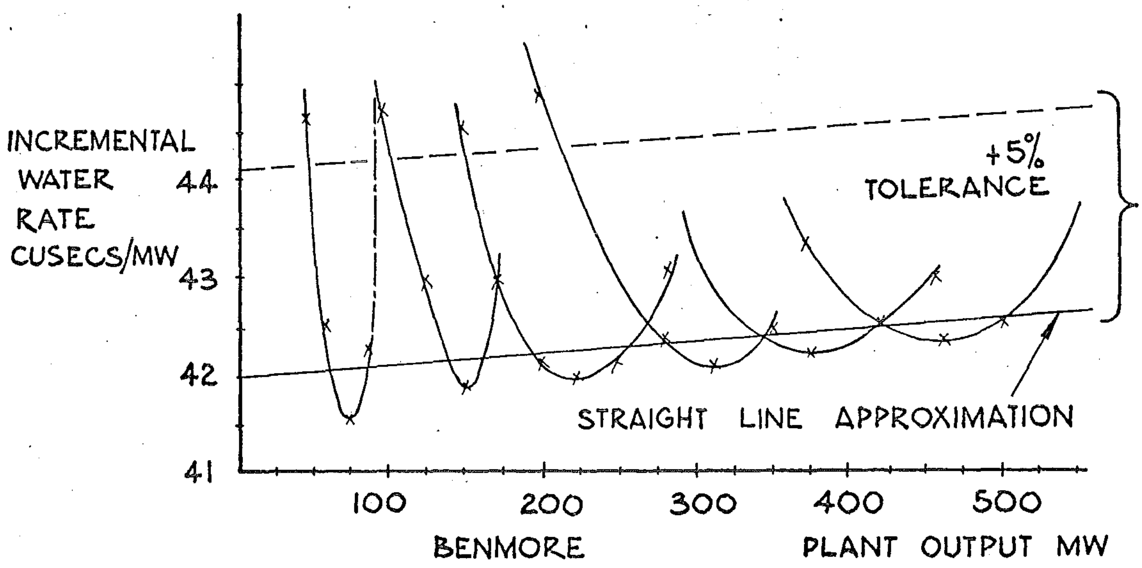

fig. 4·1 TYPICAL INCREMENTAL WATER RATE CURVE multisegment representation would be worthwhile until the accuracy of the plant data is known. (Kirchmayer in reference 3 has shown the importance of accurate plant data and the likely cost to the system if the accurate data is not known.)

The following plant characteristics have been used:-

Busbar No.	W_{nn} (slope) Cusecs/(MW)^2	W_n (intercept) Cusecs/MW
1	0.001	26.13
2	0.035	38.00
3	0.025	7.50
4	0.025	77.00

The almost flat slope of the incremental water rate for Busbar 1 is worth noting, (the flat slope is due to the amalgamation of three relatively large stations). It was anticipated that this almost flat curve would cause instability in the convergence of the iterative solutions, but no serious problems eventuated. The large disparity of the incremental water rates of each plant is reflected in the water values which have been used as the standard values for the development of the program.

$\gamma_1 = 25.00 \qquad \gamma_2 = 18.00 \qquad \gamma_3 = 90.00 \qquad \gamma_4 = 8.50$

γ in \$/(cu.ft $\times 10^6$)

4.1.3 Loss Formula Coefficients:

The system is described by the loss formula transmission coefficients (B coefficients). The errors in this representation by the coefficients are less than $2\frac{1}{2}\%$

(figure 4.2) with the correct estimation of the linear relationship between the real and reactive power output at each busbar, which is a particularly sensitive parameter in calculating these coefficients. Multiple sets of B coefficients to simulate the dynamic character of the system as the load demand varies have not yet been used, as the average set of B coefficients proved adequate for the program development.

4.1.4 Water Values (γ's):

The value of the water at a given busbar is not accurately known, and in an all hydro system, such as modelled, are not true values either, as there is no reference to which these values may be pegged. It is the relativity of the water values, rather than their absolute value which is altered to satisfy the specified water constraints. Once thermal plant is introduced into the system, or, the hydro system interconnected to a thermal based system, then a true value can be placed on the hydro generation in terms of the cost of its replacement by thermal generation. Consequently, the accuracy of the initial water values in an all hydro system, insofar as the output schedule is concerned is immaterial, as they are modified in order to meet the water constraints.

4.1.5 Specified Water Constraints:

The water constraints specified are derived from the long term resource allocation and the expected accuracy of these values is 5%. The specified water constraints are the desired average water consumption over a given period

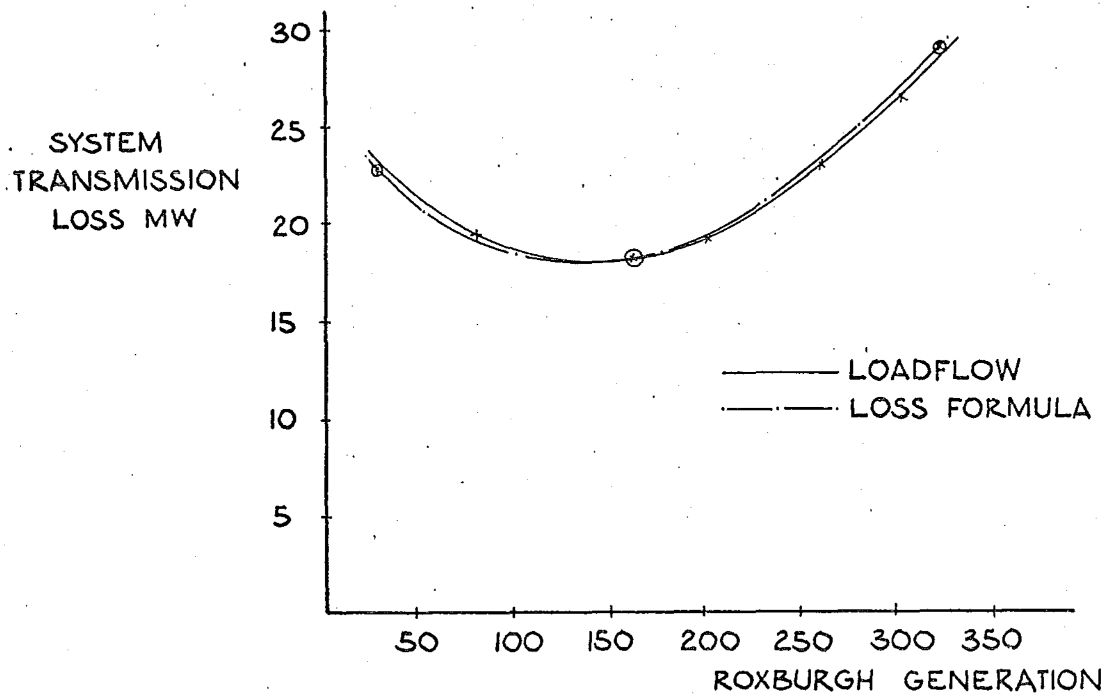

fig. 4.2 COMPARISON OF LOSSES CALCULATED BY:-
(i) LOAD FLOW (ii) LOSS FORMULA WITH CONSTANT LOAD

(usually one week). Operating conditions over each day may require significant daily variation around these average figures, therefore the accuracy of 1% used as a target for convergence of the water constraints could be considered excessive in terms of the accuracy of the input data. However, since the main aim of this project was to evaluate and apply the method discussed to the N.Z. power system, and ensure satisfactory results, 1% tolerance for the water constraint convergence was selected as a suitable goal, and this has been achieved. (Dandeno[10] for comparative purposes achieved 0.2% tolerance in convergence.)

4.2 Schedule Output

Typical output schedules are shown (figures 4.3, 4.4), illustrating the two basic forms of the schedule output.

(i) Optimum schedule - water constraints satisfied (within 1%)

(ii) "Best Fit" schedule - calculated schedule, closest to satisfying the water constraints which are not feasible due to over-riding system load demand and generation constraints.

If a "Best Fit" schedule is output, this schedule may sometimes be marginally improved on reassessment of the specified water constraints and water values by the system control operator, if certain water constraints are more important. In reassessing the schedule, any diagnostic messages output may also be of assistance to the operator and these are illustrated in figures 4.5 to 4.8, together with further examples of generation schedules.

SOUTH ISLAND LOAD ALLOCATION.
(4 BUSBARS)

HOURLY DEMAND (MW.) -

240.00	230.00	216.00	220.00	240.00	400.00	600.00	620.00
600.00	600.00	620.00	600.00	545.00	540.00	550.00	600.00
660.00	640.00	620.00	600.00	530.00	450.00	320.00	280.00

SPECIFIED WATER CONSTRAINTS.

WAITAKI BASIN	HIGHBANK COLERIDGE	COBB	ROXBURGH	
		100	20000	(CUSECS)
CORRESPONDING WATER VALUES.				
25.000	18.000	95.000	6.700	($/MILLION CU.FT.)

****

OPTIMUM SCHEDULE.

PLANT GENERATION WAITAKI BASIN	HIGHBANK COLERIDGE	COBB	ROXBURGH	TOTAL GENERATION	SYSTEM TRANSMISSION LOSS	RECEIVED POWER	INCREMENTAL COST (LAMBDA)	SPINNING RESERVE	HOUR
90.00*	15.00*	5.00*	135.64	245.64	5.64	240.00	2.2360	108.59	1
90.00*	15.00*	5.00*	124.94	234.94	4.93	230.00	2.2156	119.29	2
90.00*	15.00*	5.00*	110.05	220.05	4.04	216.00	2.1876	94.18	3
90.00*	15.00*	5.00*	114.29	224.29	4.28	220.00	2.1955	89.94	4
90.00*	15.00*	5.00*	135.64	245.64	5.64	240.00	2.2360	108.59	5
155.30	15.00*	5.00*	242.72	418.02	18.02	400.00	2.4604	161.21	6
301.65	27.65	17.58	283.52	630.41	30.40	600.00	2.5520	180.41	7
315.89	29.16	19.20	287.62	651.87	31.87	620.00	2.5611	158.95	8
301.65	27.65	17.58	283.52	630.40	30.40	600.00	2.5520	180.42	9
301.65	27.65	17.58	283.52	630.40	30.40	600.00	2.5520	180.42	10
315.89	29.16	19.20	287.62	651.87	31.87	620.00	2.5611	158.95	11
301.65	27.65	17.58	283.52	630.40	30.40	600.00	2.5520	180.42	12
262.61	23.53	13.19	272.31	571.64	26.64	545.00	2.5274	99.95	13
259.07	23.15	12.79	271.30	566.31	26.31	540.00	2.5251	105.28	14
266.15	23.90	13.58	273.33	576.96	26.96	550.00	2.5296	94.63	15
301.65	27.65	17.58	283.52	630.40	30.40	600.00	2.5520	180.42	16
344.43	32.19	22.47	295.87	694.95	34.96	660.00	2.5794	121.20	17
330.15	30.67	20.83	291.74	673.39	33.39	640.00	2.5702	137.43	18
315.89	29.16	19.20	287.62	651.87	31.87	620.00	2.5611	158.95	19
301.65	27.65	17.58	283.52	630.41	30.40	600.00	2.5520	180.41	20
251.99	22.41	12.00	269.27	555.67	25.68	530.00	2.5207	115.91	21
195.57	16.48	5.80	253.19	471.03	21.03	450.00	2.4859	117.43	22
90.00*	15.00*	5.00*	223.69	333.68	13.69	320.00	2.4136	100.54	23
90.00*	15.00*	5.00*	179.13	289.12	9.12	280.00	2.3215	105.10	24

(AVERAGE FLOWS (CUSECS))

5998.	883.	100.	20013.

WATER VALUE (GAMMA) $/MILLION CU.FT

25.000	18.000	97.137	7.193

****

SYSTEM STATISTICS -
TOTAL GENERATION = 12059.35 MWH. TRANSMISSION LOSS = 538.36 MWH. TOTAL DEMAND = 11520.58 MWH.

Figure 4.3

SOUTH ISLAND LOAD ALLOCATION.
(4 BUSBARS)

HOURLY DEMAND (MW.) -

240.00	230.00	216.00	220.00	240.00	400.00	600.00	620.00
600.00	600.00	620.00	600.00	545.00	540.00	550.00	600.00
660.00	640.00	620.00	600.00	530.00	450.00	320.00	280.00

SPECIFIED WATER CONSTRAINTS.

WAITAKI BASIN	HIGHBANK COLERIDGE	COBB	ROXBURGH	
	1300		24000	(CUSECS)

CORRESPONDING WATER VALUES.

24.600	16.600	89.000	6.200	($/MILLION CU.FT.)

***

BEST FIT. - CONSTRAINED SCHEDULE.

PLANT GENERATION: WAITAKI BASIN	HIGHBANK COLERIDGE	COBB	ROXBURGH	TOTAL GENERATION	SYSTEM TRANSMISSION LOSS	RECEIVED POWER	INCREMENTAL COST (LAMBDA)	SPINNING RESERVE	HOUR
90.00*	15.00*	5.00*	135.64	245.64	5.64	240.00	1.9272	108.59	1
90.00*	15.00*	5.00*	124.93	234.93	4.93	230.00	1.9096	119.30	2
90.00*	15.00*	5.00*	110.04	220.04	4.04	216.00	1.8854	94.19	3
90.00*	15.00*	5.00*	114.28	224.28	4.28	220.00	1.8923	89.95	4
90.00*	15.00*	5.00*	135.64	245.64	5.64	240.00	1.9272	108.59	5
90.00*	15.00*	5.00*	316.44	426.44	26.44	400.00	2.2593	87.79	6
242.89	44.30	25.00*	320.00*	632.19	32.18	600.01	2.4729	126.76	7
262.31	46.07	25.00*	320.00*	653.39	33.37	620.01	2.4850	120.56	8
235.74	43.44	32.00*	320.00*	631.18	31.16	600.02	2.4665	138.43	9
235.74	43.44	32.00*	320.00*	631.18	31.16	600.02	2.4665	138.43	10
255.12	45.21	32.00*	320.00*	652.33	32.31	620.01	2.4785	132.28	11
235.74	43.44	32.00*	320.00*	631.18	31.16	600.02	2.4665	138.43	12
186.86	39.10	28.03	320.00*	573.99	28.94	545.05	2.4377	131.39	13
182.49	38.72	27.60	320.00*	568.81	28.76	540.05	2.4352	136.57	14
191.23	39.49	28.45	320.00*	579.16	29.11	550.05	2.4403	126.22	15
235.74	43.44	32.00*	320.00*	631.18	31.16	600.02	2.4665	138.43	16
301.39	49.65	25.00*	320.00*	696.04	36.03	660.01	2.5097	171.81	17
281.81	47.86	25.00*	320.00*	674.67	34.66	640.01	2.4973	103.18	18
262.31	46.07	25.00*	320.00*	653.39	33.37	620.01	2.4850	120.56	19
242.89	44.30	25.00*	320.00*	632.19	32.18	600.01	2.4729	126.76	20
175.51	38.16	25.00*	320.00*	558.67	28.65	530.02	2.4317	141.38	21
104.38	31.84	20.17	320.00*	476.38	26.34	450.04	2.3908	109.44	22
90.00*	15.00*	5.00*	223.69	333.69	13.69	320.00	2.0803	100.54	23
90.00*	15.00*	5.00*	179.11	289.11	9.12	279.99	2.0009	105.12	24

(AVERAGE FLOWS (CUSECS))

4777.	1320.	163.	22702.

WATER VALUE (GAMMA) $/MILLION CU.FT

24.600	16.600	89.000	6.200

***

SYSTEM STATISTICS -
TOTAL GENERATION = 12095.67 MWH. TRANSMISSION LOSS = 574.34 MWH. TOTAL DEMAND = 11521.32 MWH.

Figure 4.4

Figure 4.5 - Optimum Schedule with all four busbars constrained.

" 4.6 - Energy Balance test diagnostic. Also in this case, reassessment of water values could enable a closer result to be achieved at Busbar 2 ($\gamma_2 = 16.63$ say).

" 4.7 - Water Constraint input non-feasible, and consequently modified to a value compatible with the generation limits specified.

" 4.8(a) - Energy test - detection of non-feasible solution.

" " (b) - Demand outside range of generation specified by generation limits.

4.3 Evaluation of Savings

As the system being studied is an entirely hydro system, it is very difficult to assign a value to any given generation schedule, and consequently, when comparing a number of schedules, to evaluate the savings. If the system modelled is taken as an integral part of the N.Z. power system, including the inter-island D.C. link, then any losses or excessive generation may be costed on the basis of thermal replacement, assuming the difference in generation could have been transferred north.

For comparative purposes, a number of representative load demand patterns were scheduled manually, assuming that COBB (Busbar 3) was block loaded (25 MW) and the remaining plant at minimum generation plus the difference

SOUTH ISLAND LOAD ALLOCATION.
(4 BUSBARS)

HOURLY DEMAND (MW.) -

240.00	230.00	216.00	220.00	240.00	400.00	600.00	620.00
600.00	600.00	620.00	600.00	545.00	540.00	550.00	600.00
660.00	640.00	620.00	600.00	530.00	450.00	320.00	280.00

SPECIFIED WATER CONSTRAINTS.

WAITAKI BASIN	HIGHBANK COLERIDGE	COBB	ROXBURGH	
10000	1000	180	5690	(CUSECS)

CORRESPONDING WATER VALUES.

25.000	18.000	90.000	8.500	($/MILLION CU.FT.)

ENERGY BALANCE TEST ; RESULT MARGINAL, REASSESSMENT OF SPECIFIED CONSTRAINTS MAY BECOME NECESSARY.

****

OPTIMUM SCHEDULE.

PLANT GENERATION WAITAKI BASIN	HIGHBANK COLERIDGE	COBB	ROXBURGH	TOTAL GENERATION	SYSTEM TRANSMISSION LOSS	RECEIVED POWER	INCREMENTAL COST (LAMBDA)	SPINNING RESERVE	HOUR
202.26	15.00*	7.05	20.00*	244.31	4.33	239.99	2.5194	100.25	1
192.79	15.00*	6.18	20.00*	233.97	3.97	230.00	2.5137	110.59	2
179.50	15.00*	5.00*	20.00*	219.50	3.50	216.00	2.5057	119.73	3
183.31	15.00*	5.31	20.00*	223.62	3.63	219.99	2.5080	115.61	4
202.26	15.00*	7.05	20.00*	244.31	4.33	239.99	2.5194	100.25	5
320.33	16.40	20.42	53.74	410.89	10.89	400.00	2.5948	148.23	6
469.55	32.60	25.00*	97.76	624.90	24.91	599.99	2.6983	151.25	7
485.09	34.32	25.00*	102.33	646.74	26.75	619.99	2.7096	133.31	8
463.23	31.75	32.00*	96.83	623.81	23.82	599.99	2.6915	163.00	9
463.23	31.75	32.00*	96.83	623.81	23.82	599.99	2.6915	163.00	10
479.75	33.45	32.00*	101.39	645.60	25.61	619.99	2.7027	141.21	11
463.23	31.75	32.00*	96.83	623.81	23.82	599.99	2.6915	163.00	12
420.82	27.09	32.00*	84.42	564.33	19.29	545.04	2.6611	77.48	13
417.03	26.67	31.90	83.30	558.91	18.91	540.00	2.6584	73.67	14
424.61	27.50	32.00*	85.52	569.64	19.67	549.96	2.6638	72.17	15
463.23	31.75	32.00*	96.83	623.81	23.82	599.99	2.6915	163.00	16
516.32	37.77	25.00*	111.54	690.62	30.63	659.99	2.7327	104.43	17
500.68	36.04	25.00*	106.92	668.64	28.65	639.99	2.7211	126.41	18
485.09	34.32	25.00*	102.33	646.74	26.75	619.99	2.7096	133.31	19
469.55	32.60	25.00*	97.76	624.90	24.91	599.99	2.6983	151.25	20
415.47	26.66	25.00*	81.93	549.06	19.06	529.99	2.6594	78.19	21
354.77	20.05	24.46	64.22	463.49	13.48	450.00	2.6171	104.86	22
261.87	15.00*	13.71	36.64	327.22	7.22	320.00	2.5571	92.67	23
232.21	15.00*	10.36	28.10	285.67	5.68	280.00	2.5382	113.89	24

(AVERAGE FLOWS (CUSECS))

10026.	1003.	180.	5692.

WATER VALUE (GAMMA) $/MILLION CU.FT

25.497	18.396	93.324	8.915

****

SYSTEM STATISTICS -
TOTAL GENERATION = 11938.28 MWH. TRANSMISSION LOSS = 417.45 MWH. TOTAL DEMAND = 11520.83 MWH.

Figure 4.5

SOUTH ISLAND LOAD ALLOCATION.
(4 BUSBARS)

HOURLY DEMAND (MW.) -

240.00	230.00	216.00	220.00	240.00	400.00	600.00	620.00
600.00	600.00	620.00	600.00	545.00	540.00	550.00	600.00
660.00	640.00	620.00	600.00	530.00	450.00	320.00	280.00

SPECIFIED WATER CONSTRAINTS.

WAITAKI BASIN	HIGHBANK COLERIDGE	COBB	ROXBURGH	
12000	1300			(CUSECS)

CORRESPONDING WATER VALUES.

22.000	17.000	95.000	8.600	($/MILLION CU.FT.)

ENERGY BALANCE TEST : RESULT MARGINAL, REASSESSMENT OF SPECIFIED CONSTRAINTS MAY BECOME NECESSARY.

****

BEST FIT. - CONSTRAINED SCHEDULE.

PLANT GENERATION WAITAKI BASIN	HIGHBANK COLERIDGE	COBB	ROXBURGH	TOTAL GENERATION	SYSTEM TRANSMISSION LOSS	RECEIVED POWER	INCREMENTAL COST (LAMBDA)	SPINNING RESERVE	HOUR
204.47	15.00*	5.00*	20.00*	244.47	4.47	240.00	1.9899	94.76	1
194.04	15.00*	5.00*	20.00*	234.04	4.05	230.00	1.9847	105.19	2
179.50	15.00*	5.00*	20.00*	219.50	3.50	216.00	1.9775	119.73	3
183.65	15.00*	5.00*	20.00*	223.65	3.65	220.00	1.9795	115.58	4
204.47	15.00*	5.00*	20.00*	244.47	4.47	240.00	1.9899	94.76	5
361.80	27.04	5.00*	20.00*	413.85	13.86	399.99	2.0703	100.98	6
562.98	45.75	5.00*	20.00*	633.73	33.73	599.99	2.1812	63.90	7
583.58	47.68	5.00*	20.00*	656.26	36.26	619.99	2.1931	135.27	8
562.98	45.75	5.00*	20.00*	633.73	33.73	599.99	2.1812	63.90	9
562.98	45.75	5.00*	20.00*	633.73	33.73	599.99	2.1812	63.90	10
583.58	47.68	5.00*	20.00*	656.26	36.26	619.99	2.1931	135.27	11
562.98	45.75	5.00*	20.00*	633.73	33.73	599.99	2.1812	63.90	12
506.80	40.49	5.00*	20.00*	572.29	27.30	544.99	2.1492	125.34	13
501.72	40.02	5.00*	20.00*	566.75	26.75	539.99	2.1463	126.98	14
511.88	40.97	5.00*	20.00*	577.85	27.85	549.99	2.1520	119.78	15
562.98	45.75	5.00*	20.00*	633.73	33.73	599.99	2.1812	63.90	16
625.05	51.58	5.00*	20.00*	701.63	41.64	659.99	2.2174	104.90	17
604.27	49.62	5.00*	20.00*	678.89	38.90	639.99	2.2052	112.64	18
583.58	47.68	5.00*	20.00*	656.26	36.26	619.99	2.1931	135.27	19
562.98	45.75	5.00*	20.00*	633.73	33.73	599.99	2.1812	63.90	20
491.59	39.08	5.00*	20.00*	555.67	25.68	529.99	2.1407	123.06	21
411.31	31.62	5.00*	20.00*	467.93	17.93	449.99	2.0967	61.90	22
283.66	19.86	5.00*	20.00*	328.52	8.50	320.01	2.0298	88.51	23
245.02	16.32	5.00*	20.00*	286.34	6.34	280.00	2.0103	111.79	24

(AVERAGE FLOWS (CUSECS))

11804.	1395.	38.*	1550.*

WATER VALUE (GAMMA) $/MILLION CU.FT

20.122	14.135	95.000	8.600

****

SYSTEM STATISTICS -

TOTAL GENERATION = 12086.91 MWH. TRANSMISSION LOSS = 566.08 MWH. TOTAL DEMAND = 11520.83 MWH.

Figure 4.6

SOUTH ISLAND LOAD ALLOCATION.
(4 BUSBARS)

HOURLY DEMAND (MW.) -

240.00	230.00	216.00	220.00	240.00	400.00	600.00	620.00
600.00	600.00	620.00	600.00	545.00	540.00	550.00	600.00
660.00	640.00	620.00	600.00	530.00	450.00	320.00	280.00

SPECIFIED WATER CONSTRAINTS.

WAITAKI BASIN	HIGHBANK COLERIDGE	COBB	ROXBURGH	
7000		223*	14500	(CUSECS)

CORRESPONDING WATER VALUES.

25.000	18.000	90.000	8.500	($/MILLION CU.FT.)

ONE OR MORE OF THE WATER CONSTRAINTS SPECIFIED, IS EITHER SPECIFIED ON THE LIMIT, OR, SPECIFIED OUTSIDE RANGE AND HENCE MODIFIED TO THE APPROPRIATE LIMIT.

****

OPTIMUM SCHEDULE.

PLANT GENERATION: WAITAKI BASIN	HIGHBANK COLERIDGE	COBB	ROXBURGH	TOTAL GENERATION	SYSTEM TRANSMISSION LOSS	RECEIVED POWER	INCREMENTAL COST (LAMBDA)	SPINNING RESERVE	HOUR
90.00*	15.00*	25.00*	113.69	243.69	3.70	239.99	2.4133	91.86	1
90.00*	15.00*	25.00*	103.16	233.16	3.16	229.99	2.3917	102.39	2
90.00*	15.00*	22.26	91.43	218.69	2.69	216.00	2.3695	116.86	3
90.00*	15.00*	23.15	94.66	222.81	2.81	220.00	2.3756	112.74	4
90.00*	15.00*	25.00*	113.69	243.69	3.70	239.99	2.4133	91.86	5
200.49	18.94	25.00*	166.31	410.74	10.74	400.00	2.5330	113.71	6
354.80	35.50	25.00*	209.00	624.29	24.31	599.99	2.6368	115.76	7
370.47	37.20	25.00*	213.37	646.03	26.05	619.99	2.6478	94.01	8
348.32	34.65	32.00*	208.23	623.20	23.22	599.99	2.6302	127.51	9
348.32	34.65	32.00*	208.23	623.20	23.22	599.99	2.6302	127.51	10
363.96	36.34	32.00*	212.60	644.90	24.91	619.99	2.6411	105.81	11
348.32	34.65	32.00*	208.23	623.20	23.22	599.99	2.6302	127.51	12
305.57	30.04	32.00*	196.34	563.95	18.93	545.02	2.6008	142.86	13
301.71	29.63	32.00*	195.27	558.60	18.56	540.03	2.5982	148.21	14
309.43	30.46	32.00*	197.41	569.30	19.29	550.01	2.6035	137.51	15
348.32	34.65	32.00*	208.23	623.20	23.22	599.99	2.6302	127.51	16
401.94	40.62	25.00*	222.18	689.74	29.75	659.98	2.6700	69.21	17
386.18	38.70	25.00*	217.77	667.85	27.87	639.98	2.6588	87.20	18
370.47	37.20	25.00*	213.37	646.03	26.05	619.99	2.6478	94.01	19
354.80	35.50	25.00*	209.00	624.29	24.31	599.99	2.6368	115.76	20
300.34	29.63	25.00*	193.85	548.81	18.77	530.04	2.5993	147.34	21
238.64	23.01	25.00*	176.80	463.45	13.49	449.96	2.5580	123.80	22
137.62	15.00*	25.00*	149.48	327.10	7.11	319.99	2.4924	63.45	23
104.68	15.00*	25.00*	140.96	285.65	5.65	280.00	2.4714	89.90	24

(AVERAGE FLOWS (CUSECS))

6990.	1085.	222.	14513.

WATER VALUE (GAMMA) $/MILLION CU.FT

25.576	18.000	83.232	7.948

****

SYSTEM STATISTICS -

TOTAL GENERATION = 11925.57 MWH. TRANSMISSION LOSS = 404.70 MWH. TOTAL DEMAND = 11520.86 MWH.

Figure 4.7

SOUTH ISLAND LOAD ALLOCATION.
(4 BUSBARS)

HOURLY DEMAND (MW.) -

240.00	230.00	216.00	220.00	240.00	400.00	600.00	620.00
600.00	600.00	620.00	600.00	545.00	540.00	550.00	600.00
660.00	640.00	620.00	600.00	530.00	450.00	320.00	280.00

SPECIFIED WATER CONSTRAINTS.

WAITAKI BASIN	HIGHBANK COLERIDGE	COBB	ROXBURGH	
2359*			20000	(CUSECS)

CORRESPONDING WATER VALUES.

25.000	17.000	90.000	8.000	($/MILLION CU.FT.)

ONE OR MORE OF THE WATER CONSTRAINTS SPECIFIED, IS EITHER SPECIFIED ON THE LIMIT, OR, SPECIFIED OUTSIDE RANGE AND HENCE MODIFIED TO THE APPROPRIATE LIMIT.

REASSESSMENT OF THE SPECIFIED WATER CONSTRAINTS AND / OR WATER VALUES REQUIRED.

ACTUAL MEAN FLOW (CUSECS).

7473.	1445.	184.	12535.

SOUTH ISLAND LOAD ALLOCATION.
(4 BUSBARS)

HOURLY DEMAND (MW.) -

240.00	230.00	216.00	220.00	240.00	400.00	600.00	620.00
60.00	600.00	620.00	600.00	545.00	540.00	550.00	600.00
660.00	640.00	620.00	600.00	530.00	450.00	320.00	280.00

SPECIFIED WATER CONSTRAINTS.

WAITAKI BASIN	HIGHBANK COLERIDGE	COBB	ROXBURGH	
	2405*		15000	(CUSECS)

CORRESPONDING WATER VALUES.

25.576	13.913	83.232	7.783	($/MILLION CU.FT.)

ONE OR MORE OF THE WATER CONSTRAINTS SPECIFIED, IS EITHER SPECIFIED ON THE LIMIT, OR, SPECIFIED OUTSIDE RANGE AND HENCE MODIFIED TO THE APPROPRIATE LIMIT.

DEMAND OUTSIDE RANGE OF AVAILABLE GENERATION.

Figure 4.8

between the total demand and losses, and the total minimum generation allocated pro-rata. (This distribution is a close approximation to that which would be scheduled at present by the system control operator with minimal water constraints.) From these sample schedules, the average water flows were obtained, and these flows were then assumed to be the specified water constraints for the economic scheduling program, which then calculated the optimum schedules for the sample load demand patterns. The results of these comparative runs were disappointing in terms of the expected savings, the average savings achieved between the pro-rata scheduling and the economic scheduling being 4.5 MWh/day, worth about $15 per day ($5500 per annum) costed at $3500/GWh the thermal replacement cost. This amount is small in terms of the savings expected from the actual system. Similarly, with scheduling done on an equal incremental production cost basis for the same schedules, achieved savings of 6.2 MWh/day.

As a further case for comparison, a number of load patterns were scheduled by -

(i) the co-ordination equations

(ii) equal incremental cost of production (i.e., no <u>incremental</u> transmission losses)

with the same water values and no specified water constraints thereby simulating an all thermal system. The difference between the schedules in terms of the cost of transmission losses averaged $200,000 per annum (160 MWh/day).

In an all hydro system where the water has no true value, if the criterion of economic scheduling is modified to place more emphasis on the transmission losses (using the linear approximations for the co-ordination equations), while meeting the water constraints, then more significant savings can be made.

To a limited extent, the small gain in scheduling economically with all busbars constrained compared with other forms of scheduling, is due to the simplicity of the System Model. The present model closely represents the basic 220 kV transmission system with small modifications, from Roxburgh through to Kikiwa (refer figure 4.9). The losses in the 220 kV system are less than those associated with the lower voltage transmission lines. The lumping of all the load on to the 220 kV busbars also contributes to this inaccuracy, as the load correctly modelled would increase the losses. At constant system load (P_R^d = 500 MW) the effect of swinging the generation around the system is shown in the table below and shows the inaccuracy of the model (refer to figure 4.2 also):-

Roxburgh Generation (MW)	Model Losses (MW)	Actual System Losses (MW)
30	23.2	23.1
160	18.4	25.7
320	28.4	43.5

The majority of the error being due to the neglecting of the secondary transmission network and loads, hence the need for an improved system model.

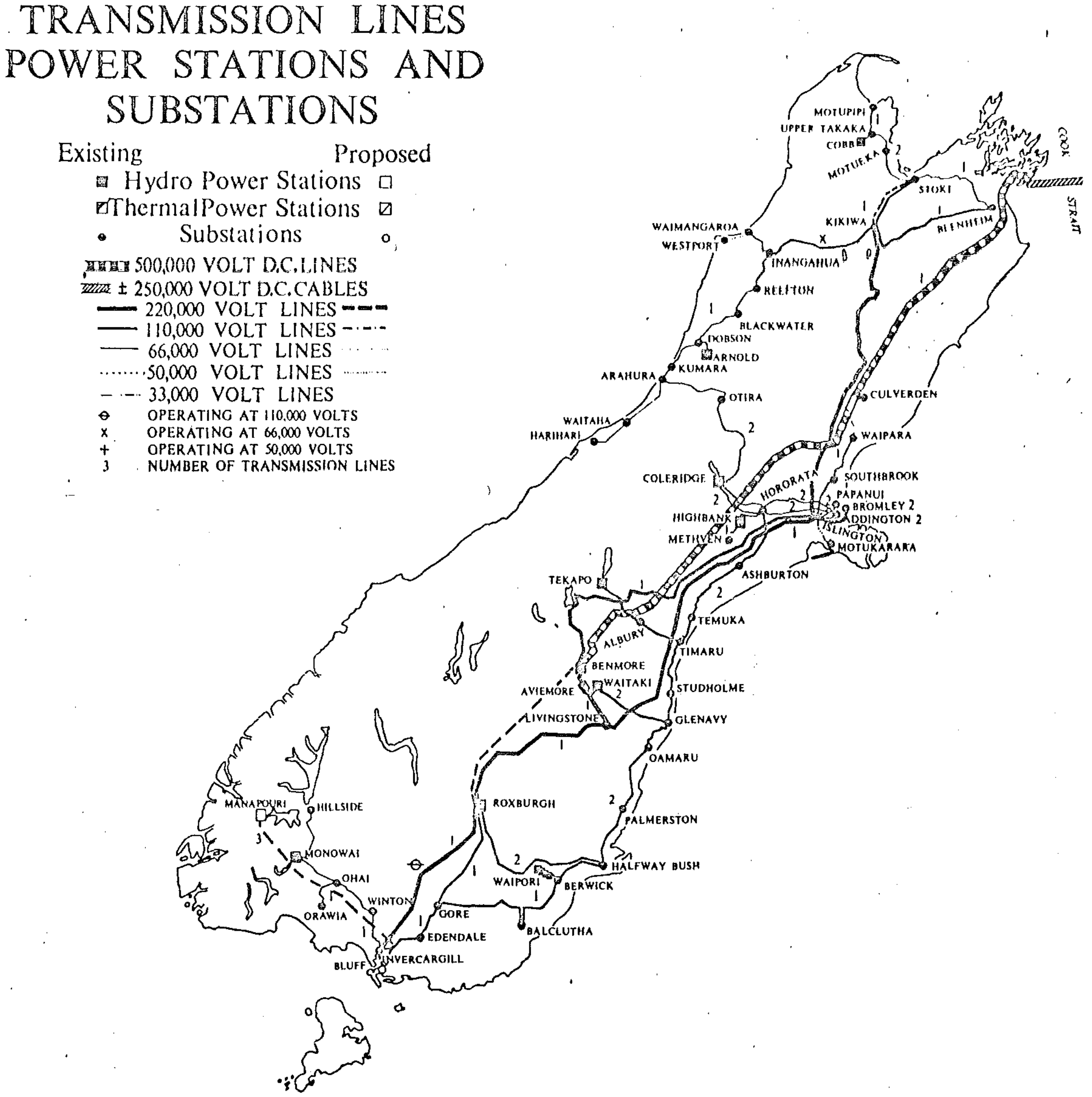
TRANSMISSION LINES
POWER STATIONS AND
SUBSTATIONS
Existing
Proposed
Hydro Power Stations
Thermal Power Stations
Substations
500,000 VOLT D.C.LINES
± 250,000 VOLT D.C.CABLES
220,000 VOLT LINES
110,000 VOLT LINES
66,000 VOLT LINES
50,000 VOLT LINES
33,000 VOLT LINES
OPERATING AT 110,000 VOLTS
OPERATING AT 66,000 VOLTS
OPERATING AT 50,000 VOLTS
NUMBER OF TRANSMISSION LINES
MOTUPIPI
UPPER TAKAKA
COBB
MOTUEKA
STOKE
BLENHEIM
COOK STRAIT
KIKIWA
WAIMANGAROA
WESTPORT
INANGAHUA
REEFTON
BLACKWATER
DOBSON
ARNOLD
KUMARA
ARAHURA
OTIRA
WAITAHA
HARIHARI
CULVERDEN
WAIPARA
SOUTHBROOK
PAPANUI
BROMLEY 2
ADDINGTON 2
ISLINGTON
MOTUKARARA
COLERIDGE
HORORATA
HIGHBANK
METHVEN
ASHBURTON
TEKAPO
ALBURY
TEMUKA
TIMARU
BENMORE
WAITAKI
AVIEMORE
STUDHOLME
LIVINGSTONE
GLENAVY
OAMARU
ROXBURGH
PALMERSTON
HALFWAY BUSH
WAIPORI
BERWICK
BALCLUTHA
MANAPOURI
HILLSIDE
MONOWAI
OHAI
ORAWIA
WINTON
GORE
EDENDALE
INVERCARGILL
BLUFF

Figure 4.9

4.4 Alternative Methods for Economic Scheduling

This report has considered only the co-ordination equation method (based on the calculus of variations) in detail, but in recent years, a number of new techniques have been developed, which can be applied to economic scheduling. This subsection is a brief resume of some of these methods, which are themselves a subject worthy of much more study.

(i) Dynamic Programming: Basically the dynamic programming methods[18, 19, 20], in effect, for a given set of system conditions, operate the system in every possible combination of hydro and thermal generation from hour to hour, and then select that combination of hour to hour scheduling that results in the minimum thermal cost over the operating period. Kirchmayer in reference 20, and Carpentier in the discussion of reference 20, after comparing the dynamic programming and variational calculus formulations, conclude that the variational calculus methods appear to hold the better potential for application of the methods to large scale systems.

(ii) Linear Programming: This method of describing the system by a set of linear equations has been used for economic scheduling[21] by several authors with some success. Since the losses in a power system are nonlinear, the calculation of these losses using linear approximations and other devices is one of the most difficult aspects, and linear programming as such has not been used extensively to date.

(iii) Nonlinear Programming: It is in this field of optimization techniques that the biggest advances have been made, and where a method suitable for application to the N.Z. Power System is likely to be found, as an alternative to the method evaluated. The references quoted are a selection from papers on the recent developments based on techniques using for example, Pontryagins Maximum Principle[22], and gradient methods[23, 24]. The bibliography of a paper by Stott, Humpage and Brameller[25] is a recommended source for references on these modern techniques.

In addition to the above methods, several authors have combined methods, taking advantage of the strong points of each and used them for economic scheduling[26, 27].

4.5 <u>Conclusions</u>

(i) With all busbars in an all hydro system constrained by the water allocation requirements, there is no freedom in any parameters, in which to optimize the generation schedule. In this case, since the load demand curve implies a given amount of energy, and the water constraints similarly, provided the water constraints are feasible, the generation schedule is fixed by the energy requirements, and with constant water values, then regardless of the method of scheduling, the end result will be the same. Consequently, with all busbars constrained, the co-ordination equations method has no advantage. This conclusion may be applied to an integrated power system to a certain extent. If all hydro plant is constrained, and the thermal plant is constrained by fuel contracts which tend to limit the flexibility of operation, then economic scheduling as described in this report may be of limited value. Only where a number of busbars are unconstrained and consequently the system has some operational flexibility is it possible to make worthwhile savings with this method of economic scheduling.

(ii) In an integrated system with reasonable flexibility of operation, using incremental cost methods, the incremental transmission losses must be included if maximum benefit is to be obtained.

(iii) The system model used needs to reflect not only the main transmission network and loads, but also the higher loss secondary transmission network and its associated loads so that the load distribution may be more accurately described, and hence give a better generation schedule.

(iv) In using the South Island system for the evaluation of the techniques, it has been shown that this type of system, as modelled, does not lend itself to the achievement of large scale economics. Only with its extension to the whole of the N.Z. Power System with the consequent introduction of thermal plant and the inter-island D.C. link, suitably modelled, will the potential of economic scheduling be realized.

4.6 Recommendations

(i) Further investigation is needed into the simulation of the dynamic behaviour of the system over a given time period, using techniques such as multiple sets of loss formula coefficients and variable water values to improve the scheduling of generation with the present method.

(ii) In this report, little attention has been paid to two most important operating criteria, which should be considered along with economic scheduling, system security and unit commitment[28, 29], particularly since the security aspect is an over-riding constraint to be considered. It is suggested that further study of the interaction between these aspects and their implication in economic scheduling is warranted.

(iii) The scheduling of active power only has been dealt with, and in a power system with limited flexibility of operation because of predominant water constraints, the savings realized have been limited. The optimization of the system with respect to real and reactive power[30,31] holds much potential for N.Z. conditions, and, it is recommended that this aspect of system operation receive much more attention.

(iv) The co-ordination equations method developed has considered hydro generation with no hydraulic complications. In future development of the method, these hydraulic factors such as variable head, water transport time delay and storage constraints on hydraulically coupled stations on a single river need to be evaluated,[12, 32, 33] since these hydraulic conditions which do exist in the N.Z. system are important for realistic simulation of the system.

(v) Since the development of the classical variational calculus methods, a number of new mathematical techniques have been evolved, and applied with success to the general problem of economic load allocation. Investigation into these methods is recommended for possible complementary or alternative procedures for economic scheduling of the New Zealand Power System.

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APPENDIX A

PROGRAM LISTING AND SELECTED SYMBOL LIST

A1. Interpretation of Selected Symbols

A	No. of intervals in time period (Standard: A=24)
B	Sets of B coefficients (3 of 4 x 4)
GMAX	Station maximum generation for each interval
GMIN	Station minimum generation for each interval
WP	Slope of Incremental Water Rate curve
WC	Intercept of Incremental Water Rate curve
TC	Convergence Constant (Standard value TC = 0.01)
GAMMA	γ - the water value
WATER	specified water constraints
DEMAND	Forecast Load demand curve (A intervals)
HRLAMB	Estimated λ values
TYPE	Data input parameter defines data type
STAT	Busbar identification number for data
HR	Group of 8 time intervals 1-first, etc.

```
C
C
C     ******************************************************************
C
C      LANZOP - A PROGRAM FOR COMPUTATION OF ECONOMIC LOAD ALLOCATION.
C
C      BASIC REFERENCE - ECONOMIC OPERATION OF POWER SYSTEMS.
C            - L.K.KIRCHMAYER. WILEY 1958.
C
C     ******************************************************************
C
C
C    THE DATA IS INPUT ON 'TYPE' CARDS AND THIS DATA WILL OVERWRITE
C      THE STANDARD OPTIONS.
C
C     TYPE - 0. END OF DATA SET.
C            1. PROGRAM PARAMETERS   A,SPRINT
C            2. HOURLY MIN. GENERATION FOR GIVEN STATION O -STAT,GMIN(A)
C            3. HOURLY MAX. GENERATION FOR GIVEN STATION O STAT,GMAX(A)
C            4. B COEFFICIENTS INPUT BY STATION (STAT) AND PERIOD (HR)
C            5. STATION WATER CONVERSION FACTORS. STAT - WP , WC .
C            6. HOURLY LOAD PATTERN - DEMAND(A)
C            7. HOURLY LAMBDA VALUES - HRLAMB(A)
C            8. WATER CONSTRAINT VALUES - WATER
C            9. STATION WATER VALUES ( COSTS ) - GAMMA
C
C    THE DATA CARDS ALL HAVE A COMMON FORMAT - 3I2,2X,8F9.0  AND
C    THE PARAMETERS -  TYPE ,STAT,HR, DATIN(1-8)
C
C
C    THE FOLLOWING STANDARD OPTIONS APPLY.
C
C    THE GENERATION MINIMA AND MAXIMA ARE SET AS FOLLOWS -
C      WAITAKI  90.0  865.0     HBK/COLRDGE  15.0   60.0
C      COBB      5.0   32.0     ROXBURGH     20.0  320.0
C
C    THE WATER CONSTANTS WP &WC ARE SET AS FOLLOWS -
C      WAITAKI 0.001  26.13   HBK/COLRDGE  0.035  38.00
C      COBB    0.025   7.50   ROXBURGH     0.025  77.00
C
C    THE STANDARD LOAD TOLERANCE IS SET AT 0.01 %.
C
C    THE STANDARD PRINTOUT OPTION IS SUPPRESSED PRINTOUT OF THE
C      INTERMEDIATE RESULTS. ( SPRINT = .FALSE. . SET BY INPUT ZERO. )
C      IF UNSUPPRESSED PRINTOUT DESIRED INPUT ANY VALID NUMBER FOR
C      PARAMETER SPRINT WHICH IS THEN SET TO .TRUE.
C
C
C      COMMENT CARDS IN GENERAL DESCRIBE PROGRAM SEQUENCE.
```

```
          C
          C       BLOCK DATA SUBPROGRAM SETS UP STANDARD OPTIONS LISTED BELOW.
          C
 0001             BLOCK DATA
 0002             COMMON / STANOP / A,B,GMAX,GMIN,WP,WC,TC,ADJ,ADJLL
 0003             REAL B(4,4,3) / 16*0.0,
                 1 0.010227,-0.001913,-0.005597,0.001618,
                 2-0.001913, 0.109820,-0.001243,-0.006740,
                 3-0.005597,-0.001243, 0.026971,-0.011104,
                 4 0.001618,-0.006740,-0.011104, 0.025498,
                 5 16*0.0 /,
                 6 GMAX(24,4) / 24*865.0,24*60.0,24*32.0,24*320.0 /,
                 7 GMIN(24,4) / 24*90.0,24*15.0,24*5.0,24*20.0 /,
                 8 WP(4)/0.001,0.035,0.025,0.025/, WC(4)/26.13,38.00,7.50,77.00/,
                 9 TC / 0.01 / ,
                 A ADJ(5) / 0.000250,0.000190,0.000220,0.000200,0.000185 /,
                 B ADJLL(5) / 0.0270,0.0040,0.0008,0.0275,0.4500 /
 0004             INTEGER A/24/
 0005             END
```

```
C
C
C
      COMMON /STANDP/ A,B(4,4,3),GMAX(24,4),GMIN(24,4),WP(4),WC(4),TC
     1,ADJ(5),ADJLL(5)
      COMMON  QGAM,DEV,GAMMA(4),HGAM(4),WBYP(4),WATER(4),WUSD(4),GADJ(5)
     1,K,LM,LIN,DEMAND(24),HRLAMB(24),WMIN(4),WMAX(4),SLSQV,PLSQV,LSQV
      REAL*8 QGAM(4,4),DEV(4)
      COMMON / GRAPHA/ SHGEN(5,24),SUMG(5,24),SP(5,24),MPR(5)
      INTEGER A,WBYP,SP,AST(32),NW(4)
      LOGICAL SPRINT,WCONV
      INTEGER HCUR,TYPE,STAT,HR,IND(2),IPR(4)
      REAL TEMGAM(4),DATIN(8),MMING(4),MMAXG(4),MGEN(4),MAXG(4)
      DIMENSION RESULT(10,26),INCL(5,25)
      DATA AST/32*'****'/,IND/'     *    '/
      DATA MAXG /865.0,60.0,32.0,320.0/
C
C     INITIALIZATION OF B COEFFICIENTS, AND WATER CONSTRAINTS CLEARED.
C
      DO 3 I=1,4
      DO 2 J=1,4
      DO 1 K=1,3
      B(I,J,K)=B(I,J,K)/100.0
    1 CONTINUE
      QGAM(I,J) = 0.0D0
    2 CONTINUE
      WATER(I) = 0.0
    3 CONTINUE
      LM =0
      LIN = 0
      SPRINT = .FALSE.
C
C     DATA INPUT.( CARD )
C
    5 READ(5,600) TYPE,STAT,HR,DATIN
  600 FORMAT(3I2,2X,8F9.0)
      IF ( TYPE .EQ. 0 ) GO TO 100
    7 GO TO (10,20,30,40,50,60,70,80,90),TYPE
   10 IF(DATIN(1).NE.0.0) A=DATIN(1)+0.25
      IF(DATIN(2) .NE. 0.0) SPRINT = .TRUE.
      GO TO 5
   20 DO 25 I=1,8
      IF(DATIN(I).NE.0.0) GMIN(I+(HR-1)*8,STAT)=DATIN(I)
   25 CONTINUE
      LM = 1
      GO TO 5
   30 DO 35 I=1,8
      IF(DATIN(I).NE.0.0) GMAX(I+(HR-1)*8,STAT)=DATIN(I)
   35 CONTINUE
```

```
      LM = 1
      GO TO 5
   40 DO 45 I=1,4
      B(STAT,I,HR)=CATIN(I)/100.0
   45 CONTINUE
      GC TO 5
   5C IF(DATIN(1).NE.0.0) WP(STAT)=DATIN(1)
      IF(DATIN(2).NE.0.0) WC(STAT)=DATIN(2)
      GO TO 5
   60 DO 65 I=1,8
      DEMAND(I+(HR-1)*8)=DATIN(I)
   65 CONTINUE
      GO TO 5
   70 DO 75 I=1,8
      HRLAMB(I+(HR-1)*8)=DATIN(I)
   75 CONTINUE
      LIN = 1
      GO TO 5
   80 DO 85 I=1,4
      WATER(I)=DATIN(I)
   85 CONTINUE
      GO TO 5
   90 DO 95 I=1,4
      GAMMA(I)=DATIN(I)
   95 CONTINUE
      GO TO 5
C
C     PARAMETER INITIALISATION, WITH NO WATER CONSTRAINTS SPECIFIED.
C
  100 NEQ=4
      GADJ(5) = 0.0
      M = 0
      LC=1
      HLSQV = 0.0
      EBF = 0.01
      DSUM=0.0
      DO 101 I=1,A
      DSUM = DSUM + DEMAND(I)/A
  101 CONTINUE
      DO 115 KL=1,4
      DEV(KL) = 0.0D0
      WMIN(KL) = 0.0
      WMAX(KL) = 0.0
      MMING(KL) = 0.0
      MMAXG(KL) = 0.0
C
C     CHECK GENERATION CONSTRAINTS.  CALCULATE THE MEANS OF THE
C     GENERATION CONSTRAINTS,  MAX. & MIN. LIMITS OF WATER CONSTRAINTS.
C
```

```
      DO 102 J=1,A
      IF ( GMIN(J,KL) .LT. 0.0 ) GMIN(J,KL) = 0.0
      IF ( GMAX(J,KL) .GT. MAXG(KL) ) GMAX(J,KL) = MAXG(KL)
      WMIN(KL)=(WP(KL)*GMIN(J,KL)+WC(KL))*GMIN(J,KL)/A + WMIN(KL)
      WMAX(KL)=(WP(KL)*GMAX(J,KL)+WC(KL))*GMAX(J,KL)/A + WMAX(KL)
      MMING(KL) = MMING(KL) + GMIN(J,KL)/A
      MMAXG(KL) = MMAXG(KL) + GMAX(J,KL)/A
  102 CONTINUE
      IPR(KL) = IND(1)
      WBYP(KL)=0
      IF(WATER(KL).NE.0.0) GO TO 104
      NEQ=NEQ-1
      WBYP(KL) = KL
      GO TO 110
C
C     TEST VALIDITY OF WATER CONSTRAINTS AGAINST LIMITS IMPOSED BY
C     GENERATION CONSTRAINTS.
C
  104 IF( (WATER(KL).LT.WMAX(KL)) .AND. (WATER(KL).GT.WMIN(KL)) )
     1 GO TO 110
      IF ( WATER(KL) .LE. WMIN(KL) ) GO TO 106
      WATER(KL) = WMAX(KL)
      GO TO 108
  106 WATER(KL) = WMIN(KL)
  108 IPR(KL) = IND(2)
      M = 1
  110 NW(KL)=WATER(KL)
  115 CONTINUE
      CALL ZEROBL
C
C     OUTPUT DAILY LOAD CURVE AND SPECIFIED WATER CONSTRAINTS.
C
      WRITE(6,700) (DEMAND(I),I=1,A)
  700 FORMAT(1H8/1H1,//T30,'SOUTH ISLAND LOAD ALLOCATION.'/T38,'(4 BUSBA
     1RS)'//T20,' HOURLY DEMAND (MW.) -'/3(/T10,8F9.2)//)
      WRITE(6,704) ( (NW(I),IPR(I)),I=1,4 ),GAMMA
  704 FORMAT(/T20,'SPECIFIED WATER CONSTRAINTS.'//T11,'WAITAKI      HIG
     1HBANK',7X,'COBB          ROXBURGH'/T12,'BASIN        COLERIDGE'//T6,4(
     2I10,A4),3X,'(CUSECS)'///T20,'CORRESPONDING WATER VALUES.'//T3,4F14
     3.3,6X,'( $/MILLION CU.FT. )'//)
      CALL ZEROCH
      IF ( M .EQ. 1 ) WRITE(6,705)
  705 FORMAT('0   ONE OR MORE OF THE WATER CONSTRAINTS SPECIFIED, IS EIT
     1HER SPECIFIED ON THE LIMIT, OR, '/'        SPECIFIED OUTSIDE RANGE
     2AND HENCE MODIFIED TO THE APPROPRIATE LIMIT.'///)
      IF ( NEQ .EQ. 0 ) SPRINT = .TRUE.
      IF ( SPRINT ) WRITE(6,706) AST
  706 FORMAT('1',32A4//T50,'OPTIMUM SCHEDULE FOR WATER COSTS INPUT.'//)
      K = 5
```

```
      C
      C      CALCULATE FIRST SCHEDULE BASED ON COSTS ( GAMMAS ) INPUT.
      C      ( BASE CASE ).  GAMMAS ARE WATER VALUES IN $ / MILLION CU.FT.
      C
0116         CALL GENALL(GAMMA,.TRUE.,SPRINT,&195,&195)
0117         IF ( SPRINT ) WRITE(6,712) GAMMA
0118         WCONV = .TRUE.
0119         DO 118 I=1,4
0120         IF((ABS(WUSD(I)-WATER(I)).GT.0.01*WATER(I)).AND.(WATER(I).NE.0.0))
            1 WCONV = .FALSE.
0121     118 CONTINUE
0122         K=0
0123         LIN = 1
0124         IF ( SPRINT ) WRITE(6,707) AST
0125     707 FORMAT(/32A4/)
0126         OPSQV = SLSQV
      C
      C      IF GRAPH OF ANY SCHEDULES REQUIRED,ADD SUBROUTINES PLOTG
      C      AND GRAPH AND REMOVE C IN COLUMN 1 OF APPROPRIATE CARDS.
      C
      C      IF ( (NEQ .EQ. 0) .OR. WCONV ) CALL PLOTG(MAXG,DEMAND)
      C
      C
      C
      C      TEST FOR SATISFYING OF WATER CONSTRAINTS
      C
0127         IF ( (NEQ .EQ. 0) .OR. WCONV ) GO TO 188
      C
      C      CALCULATE THE MEAN GENERATION AND SUM OF THE EQUIVALENT
      C      AND THE SPECIFIED WATER USAGE OF THESE STATIONS.
      C      GENERATION IMPLIED IN THE DIFFERENCE BETWEEN THE NON-CONSTRAINED
      C
0128     121 TPDIFF = 0.0
0129         LSQV = 0
0130         DO 124 I=1,4
0131         MGEN(I) = SHGEN(I,1)/A
0132         DO 122 J=2,A
0133         MGEN(I) = SHGEN(I,J)/A + MGEN(I)
0134     122 CONTINUE
0135         IF ( WBYP(I) .EQ. 1 ) GO TO 124
0136         CONV = (WC(I)+WP(I)*MGEN(I))
0137         PDIFF = (WUSD(I) - WATER(I) ) / CONV
0138         TPDIFF = TPDIFF + PDIFF
0139     124 CONTINUE
0140         GSUM = 0.0
      C
      C      CALCULATE THE EQUIVALENT GENERATION AVAILABLE FOR THE
      C      NON - CONSTRAINED STATIONS, AND THEN CALCULATE THE ENERGY
      C      BALANCE TO CONFIRM THE FEASIBILITY OF SOLUTION REQUIRED.
```

```
      C
0141        IF ( NEQ .EQ. 4 ) GO TO 129
0142        DO 128 I=1,4
0143        IF ( WBYP(I) .NE. I ) GO TO 128
0144        IF ( TPDIFF ) 125,130,127
0145    125 GSUM = MMING(I) - MGEN(I) + GSUM
0146        GO TO 128
0147    127 GSUM = MGEN(I) - MMAXG(I) + GSUM
0148    128 CONTINUE
0149    129 IF ( TPDIFF .LT. 0.0 ) TPDIFF = -TPDIFF
0150        DIFF = TPDIFF + GSUM
0151        IF ( SPRINT ) WRITE(6,1000) MMAXG,MGEN,MMING,DSUM,TPDIFF,GSUM,DIFF
0152   1000 FORMAT('0   MMAXG - ',4F8.2/'      MGEN - ',4F8.2,/'     MMING - ',
           1 4F8.2/'   MEAN DEMAND =',F8.2/'    TPDIFF =',F8.2,'    GSUM =',F8.2
           2 ,'    DIFF =',F8.2,//'  -VE DIFF INDICATES SLACK IN THE SYSTEM.'/)
0153        IF ( (DIFF .GT. 0.0) .AND. (DIFF .LT. EBF*DSUM) .AND. (LC .EQ. 1))
           1 WRITE(6,708)
0154    708 FORMAT('0   ENERGY BALANCE TEST O  RESULT MARGINAL, REASSESSMENT O
           1F SPECIFIED CONSTRAINTS MAY BECOME NECESSARY.'/)
      C
      C     TEST FOR FEASIBILITY OF SOLUTICN WITH SPECIFIED CONSTRAINTS
      C     ON AN ENERGY BASIS.
      C
0155        IF ( DIFF .LT. EBF*DSUM ) GO TO 210
0156        WRITE(6,709)
0157    709 FORMAT('0     REASSESSMENT OF THE SPECIFIED WATER CONSTRAINTS AND
           1/ OR WATER VALUES REQUIRED. '//)
0158        IF ( LC .GT. 1 ) GO TO 225
0159        WRITE(6,900) WUSD
0160    900 FORMAT(/T20,'ACTUAL MEAN FLOW ( CUSECS ).',//T6,4(F11.0,3X)//)
0161        GO TO 195
0162    130 K=K+1
0163        IF((K.EQ.WBYP(K)).AND.(K.LE.3)) GO TO 130
0164        IF(WBYP(K).EQ.4) GO TO 155
0165        DO 140 I=1,4
0166        IF(K.EQ.I) GO TO 135
0167        TEMGAM(I)=GAMMA(I)
0168        GO TO 140
0169    135 TEMGAM(I)=GAMMA(I) + GADJ(I)
0170    140 CONTINUE
0171        NC = 0
0172        GO TO 150
0173    145 TEMGAM(K) = TEMGAM(K)*(1.0+SIGN(0.05,GADJ(K)))
0174        NC = 1
      C
      C     CALCULATE ELEMENTS OF JACOBIAN - D(FLOW)/D(COST) BY
      C     PERTURBING EACH CONSTRAINED STATION COST IN TURN.
      C
0175    150 IF ( SPRINT ) WRITE(6,1001) TEMGAM
```

```
 1001 FORMAT('0    TEMGAM - ',4F8.3/)
      CALL GENALL(TEMGAM,.FALSE.,.FALSE.,&195,&225)
C
C     IF NO CHANGE IN FLOW REPEAT WITH NEW COST VALUE
C
      IF ( QGAM(K,K) .EQ. 0.0 ) GO TO 145
      IF ( NC .EQ. 0 ) GO TO 153
      AVGE = 0.0
      GAMMA(K) = TEMGAM(K)
      GO TO 170
  153 IF ( K .LT. 4 ) GO TO 130
  155 IF ( SPRINT ) WRITE(6,710) GAMMA,QGAM
  710 FORMAT('0    GAMMA0',4F13.3//('0    QGAM0',4F13.3))
      IF ( NEQ .GT. 1 ) GO TO 165
C
C     GAMMA CORRECTION FOR SINGLE CONSTRAINED STATION.
C
      DO 160 I=1,4
      HGAM(I) = GAMMA(I)
      IF ( I .EQ. WBYP(I) ) GO TO 160
      AVGE = DEV(I)/(GAMMA(I) * QGAM(I,I))
      GAMMA(I) = GAMMA(I) + DEV(I)/QGAM(I,I)
  160 CONTINUE
      GO TO 170
C
C     SOLUTION OF SIMULTANEOUS EQUATIONS,
C
  165 CALL PAREQ(NEQ,AVGE,&225)
C
  170 K = 5
      IF ( SPRINT ) WRITE(6,710) GAMMA
      GADJ(5) = AVGE
      IF ( SPRINT ) WRITE(6,711) AST
  711 FORMAT('1',32A4//T50,' CONSTRAINED SCHEDULE.'//)
C
C     CALCULATE NEW ECONOMIC SCHEDULE WITH MODIFIED COSTS.
C     ( NEW BASE CASE ) .
C
  172 CALL GENALL(GAMMA,.TRUE.,SPRINT,&195,&172)
C
      K=0
      IF ( SPRINT ) WRITE(6,712) GAMMA
  712 FORMAT(/T23,'WATER VALUE (GAMMA) $/MILLION CU.FT'//T3,4F11.3/)
      IF ( SPRINT ) WRITE(6,707) AST
      IF ( SPRINT ) WRITE(6,1002) SLSQV,PLSQV
 1002 FORMAT('0    SLSQV =',F12.5,'      PLSQV =',F12.5/)
      WCONV = .TRUE.
      DO 174 I=1,4
      IF((ABS(WUSD(I)-WATER(I)).GT.0.01*WATER(I)).AND.(WATER(I).NE.0.0))
```

```
                 1 WCONV = .FALSE.
0210         174 CONTINUE
           C
           C       TEST FOR SATISFYING OF WATER CONSTRAINTS
           C
0211               IF ( WCONV ) GO TO 188
           C
           C       TEST NEW SOLUTION - ACCEPT IF A BETTER SOLUTION AS DEFINED
           C       BY OBJECTIVE FUNCTION (SEE SUBROUTINE GENALL).
           C       IF PERTURBATION UNCONSTRAINED ( NC = 0 )
           C
0212               IF ( (SLSQV .GT. PLSQV) .AND. (NC .EQ. 0) ) GO TO 176
           C
           C       IF CONSTRAINTS NOT SATISFIED AFTER 6 ATTEMPTS AT SOLUTION
           C       ACCEPT BEST FIT.
           C
0213               IF ( LC .EQ. 6 ) GO TO 225
0214               LC=LC+1
0215               IF ( SLSQV .LE. PLSQV ) GO TO 210
           C
0216         175 IF ( LSQV .EQ. 0 ) GO TO 130
0217               LSQV = 0
0218               GO TO 121
           C
           C       IF NEW SOLUTION HAS A OBJECTIVE FUNCTION ( OB ) VALUE GREATER
           C       THAN BASE CASE THEN REDUCE D(GAMMAS). (GAMMA CORRECTION
           C       FACTORS.)
           C
0219         176 IF ( (SLSQV .LE. CPSQV) .OR. (LSQV .EQ. 1) ) GO TO 180
0220               RF = SQRT(SLSQV-CPSQV)
0221               IF ( RF .LT. 1.0 ) RF = 1.0
0222               DO 178 I=1,4
0223               GAMMA(I) = HGAM(I) + (GAMMA(I)-HGAM(I) )/RF
0224         178 CONTINUE
0225               AVGE = AVGE*(1.0/RF - 1.0)
0226               GO TO 186
           C
           C       TEST VALUE OF OBJECTIVE FUNCTION OF CURRENT SCHEDULE.
           C
0227         180 IF ( ( SLSQV .GT. HLSQV ) .AND. ( LSQV .EQ. 1 ) ) GO TO 184
0228               IF ( ABS(HLSQV - SLSQV) .LT. 0.01*HLSQV ) GO TO 225
           C
           C       SOLUTION NOT AS GOOD AS CURRENT BEST FIT, HALVE D(GAMMAS)
           C
0229               DO 182 I=1,4
0230               GAMMA(I) = ( HGAM(I) + GAMMA(I) )*0.5
0231         182 CONTINUE
0232               AVGE = -0.5*AVGE
0233               GO TO 186
```

```
C
C     IF OB VALUE CVERSHOOTS APPARENT MINIMUM,SET D(GAMMAS) AT
C     MIDPOINT OF LAST TWO VALUES.
C
  184 IF ( SLSQV .GT. FLSQV ) GO TO 225
      DO 185 I=1,4
      GAMMA(I) = (GAMMA(I)-HGAM(I))*1.5 + HGAM(I)
  185 CONTINUE
      AVGE = 1.5*AVGE
  186 IF ( LSQV .EQ. 0 ) FLSQV = SLSQV
      LSQV = 1
      HLSQV = SLSQV
      GO TO 170
  188 IF ( SPRINT ) GO TO 190
C
C     OUTPUT LOAD SCHEDULE SATISFYING WATER CONSTRAINTS
C
      WRITE(6,714) AST
  714 FORMAT('1',32A4//T50,'OPTIMUM SCHEDULE.'//)
      WRITE(6,715)
  715 FORMAT(//T25,'PLANT          GENERATION',21X,'TOTAL          SYSTEM
     1RECEIVED    INCREMENTAL    SPINNING'/T65,'GENERATION  TRANSMISSION
     2 POWER',8X,'COST          RESERVE  HOUR',/T81,'LOSS',18X,'(LAMBDA)'
     3,/T8,'WAITAKI    HIGHBANK      COBB     ROXBURGH               ',T9,
     4 'BASIN    COLERIDGE'//)
      WRITE(6,720) ((((SHGEN(I,HOUR),SP(I,HOUR)),I=1,4),(SUMG(J,HOUR),
     1 J=1,5),HOUR),HOUR=1,A)
  720 FORMAT(24(/T7,4(F7.2,A4),13X,F10.2,2F12.2,F13.4,F12.2,I6//))
      WRITE(6,722) ( (WLSD(I),MPR(I)),I=1,4 )
  722 FORMAT(/T24,'( AVERAGE FLOWS ( CUSECS ) )'//T8,4(F7.0,A4)//)
      WRITE(6,712) GAMMA
      WRITE(6,707) AST
  190 TGEN = 0.0
      TLOSS = 0.0
      TLOAD = 0.0
      DO 192 I=1,A
      TGEN = TGEN + SUMG(1,I)
      TLOSS = TLOSS + SUMG(2,I)
      TLOAD = TLOAD +  SUMG(3,I)
  192 CONTINUE
      WRITE(6,724)  TGEN,TLOSS,TLOAD
  724 FORMAT('0  SYSTEM STATISTICS -  '//'   TOTAL GENERATION =',F9.2,
     1' MWH.  TRANSMISSION LOSS = ',F9.2,' MWH.  TOTAL DEMAND =',F9.2,
     2' MWH.'//)
C
C     RESTART INPUT OF DATA IF FURTHER SCHEDULES REQUIRED WITH
C     NEW WATER CONSTRAINTS.
C
C
```

```
          C     CALL PLOTG(MAXG,DEMAND)
          C
0264        195 READ(5,600,END=200) TYPE,STAT,HR,DATIN
0265            LM = 0
0266            SPRINT = .FALSE.
0267            GO TO 7
0268        200 CALL EXIT
          C
          C     STORE CURRENT OPTIMUM SCHEDULE.
          C
0269        210 DO 216 I=1,A
0270            DO 212 J=1,5
0271            RESULT(J,I) = SHGEN(J,I)
0272            RESULT(J+5,I) = SUMG(J,I)
0273            INDL(J,I) = SP(J,I)
0274        212 CONTINUE
0275        216 CONTINUE
0276            DO 220 J=1,4
0277            RESULT(J,25) = WUSC(J)
0278            RESULT(J,26) = GAMMA(J)
0279            INDL(J,25) = MPR(J)
0280        220 CONTINUE
0281            IF ( LC .EQ. 1 ) GO TO 130
0282            GO TO 175
          C
          C     OUTPUT BEST FIT SCHEDULE IF WATER CONSTRAINTS CANNOT BE SATISFIED.
          C
0283        225 WRITE(6,725) AST
0284        725 FORMAT('1',32A4//T45,' BEST FIT. - CONSTRAINED SCHEDULE.'//)
0285            WRITE(6,715)
0286            WRITE(6,720) ((((RESULT(J,L),INDL(J,L)),J=1,4),(RESULT(J,L),J=6,10
               1),L),L=1,A)
0287            WRITE(6,722) ((RESULT(J,25),INDL(J,25)),J=1,4)
0288            WRITE(6,712) (RESULT(J,26),J=1,4)
0289            WRITE(6,707) AST
0290            TLOSS = 0.0
0291            TGEN = 0.0
0292            TLOAD = 0.0
0293            DO 230 I=1,A
0294            TGEN = TGEN + RESULT(6,I)
0295            TLOSS = TLOSS + RESULT(7,I)
0296            TLOAD = TLOAD + RESULT(8,I)
0297        230 CONTINUE
0298            WRITE(6,724)  TGEN,TLOSS,TLOAD
0299            GO TO 195
0300            END
```

```
            C
            C     GENALL - SUBROUTINE CALCULATING THE ECONOMIC GENERATION SCHEDULE.
 0001             SUBROUTINE GENALL(GAMARY,FIRST,PRINT,*,*)
 0002             DIMENSION GAMARY(4),GLAMN(4),GLAMX(4),GAMC(4),GAMP(4)
 0003             COMMON /STANCP/ A,B(4,4,3),GMAX(24,4),GMIN(24,4),WP(4),WC(4),TC
                 1,ADJ(5),ADJLL(5)
 0004             COMMON  QGAM,DEV,GAMMA(4),HGAM(4),WBYP(4),WATER(4),WUSD(4),GADJ(5)
                 1,K,LM,LIN,DEMAND(24),HRLAMB(24),WMIN(4),WMAX(4),SLSQV,PLSQV,LSQV
 0005             REAL*8 QGAM(4,4),DEV(4)
 0006             LOGICAL FIRST,PRINT,CYCLE,CT
 0007             COMMON / GRAPHA/ SHGEN(5,24),SUMG(5,24),SP(5,24),MPR(5)
 0008             INTEGER SP,HOUR,A,BYPASS(4),ETC(2)
 0009             REAL LAMBDA,LOSS,WUHD(4),AUX(4),GEN(4),GENH(4),TOL(4)
 0010             REAL LAMN,LAMX
 0011             REAL AGEN(7),MACH(7)
 0012             DATA MACH / 90.0,55.0,15.0,25.0,3.9,5.33,40.0 /
 0013             DATA ETC/'    ','*   '/
 0014             DO 5 I=1,4
 0015             WUSD(I) =0.0
 0016           5 CONTINUE
 0017             HOUR=1
 0018             IF ( PRINT ) WRITE(6,700)
 0019         700 FORMAT(//T25,'PLANT        GENERATION',21X,'TOTAL         SYSTEM
                 1RECEIVED    INCREMENTAL    SPINNING'/T65,'GENERATION  TRANSMISSION
                 2 POWER',8X,'COST          RESERVE  HOUR',/T81,'LOSS',18X,'(LAMBDA)'
                 3,/T8,'WAITAKI     HIGHBANK       COBB     ROXBURGH              '/,T9,
                 4 'BASIN     COLERIDGE'//)
 0020          10 LAMBDA = HRLAMB(HOUR) * (1.0+ADJLL(K)*GADJ(K))
 0021             IC=1
            C
            C     PROVISION MADE FOR MULTIPLE SETS OF B COEFFICIENTS.
            C     STANDARD SET. NB=2.
            C
 0022             NB=2
            C
            C     CALCULATE MAXIMUM AND MINIMUM LIMITS OF LAMBDA FOR EACH STATION
            C     ( ONLY CALCULATED ONCE IF STANDARD GENERATION LIMITS APPLY
            C     FOR ALL HOURLY GENERATION ),AND MAXIMUM RANGE OF LAMBDA VALUES
            C
 0023             IF ( (LM .EQ. 0) .AND. (HOUR .GT. 1) .AND. (LIN .EQ. 1) ) GO TO 16
            C
 0024             LAMN=100.0
 0025             LAMX= 0.0
 0026             DO 14 I=1,4
 0027             SUMM=B(I,1,NB)*GMAX(HOUR,1)
 0028             SUM=B(I,1,NB)*GMIN(HOUR,1)
 0029             DO 12 J=2,4
 0030             SUMM=SUMM+B(I,J,NB)*GMAX(HOUR,J)
 0031             SUM=SUM+B(I,J,NB)*GMIN(HOUR,J)
```

```
0032        12 CONTINUE
0033           GLAMX(I)=GAMARY(I)*(WP(I)*GMAX(HOUR,I)+WC(I))*0.0036/(1.0-2.0*SUMM
              1)
0034           IF ( GLAMX(I) .GT. LAMX ) LAMX=GLAMX(I)
0035           GLAMN(I)=GAMARY(I)*(WP(I)*GMIN(HOUR,I)+WC(I))*0.0036/(1.0-2.0*SUM)
0036           IF ( GLAMN(I) .LT. LAMN ) LAMN=GLAMN(I)
0037        14 CONTINUE
0038           IF ( LIN .EQ. 0 ) LAMBDA = LAMN
      C
      C        INITIALISE GENERATION FOR ITERATIVE CALCULATION
      C
0039        16 DO 20 I=1,4
0040           GEN(I) = GMIN(HOUR,I)
0041           GENH(I)=GEN(I)
0042        20 CONTINUE
      C
      C        CALCULATE ECONOMIC LOAD ALLOCATION ON EQUAL INCREMENTAL
      C        COST OF RECEIVED POWER CONCEPT, USING GAUSS-SEIDEL ITERATIVE
      C        METHOD TO SOLVE CO-ORDINATION EQUATION
      C
0043        30 DO 45 I=1,4
0044           BYPASS(I)=0
0045           GAMP(I)=GAMARY(I)*WP(I)*0.0036/LAMBDA + 2.0*B(I,I,NB)
0046           GAMC(I)=GAMARY(I)*WC(I)*0.0036/LAMBDA
0047        45 CONTINUE
0048           IGS = 1
      C
      C        INNER LOOP OF G-S ITERATION
      C
0049        60 CYCLE=.TRUE.
0050           DO 100 N=1,4
0051           IF ( BYPASS(N) .EQ. N ) GO TO 100
0052           SUM=0.0
      C
      C        CALCULATE INCREMENTAL TRANSMISSION LOSSES.
      C
      C
0053           DO 65 M=1,4
0054           SUM1=B(N,M,NB)*GEN(M)
0055           IF(M.EQ.N) SUM1=0.0
0056           SUM=SUM+SUM1
0057        65 CONTINUE
      C
      C        CALCULATE GENERATION OF EACH STATION
      C
0058           GEN(N) = (1.0-GAMC(N) - SUM*2.0 ) / GAMP(N)
      C
      C        CONSTRAIN GENERATION TO APPROPRIATE LIMIT IF OUTSIDE RANGE
      C
```

```
      IF ( GEN(N) .GT. GMAX(HOUR,N) ) GO TO 70
      IF ( GEN(N) .LT. GMIN(HOUR,N) ) GO TO 75
      GO TO 90
   70 GEN(N)=GMAX(HOUR,N)
      GO TO 80
   75 GEN(N)=GMIN(HOUR,N)
   80 IF ( IGS .GT. 1 ) BYPASS(N) = N
   90 TOL(N)=ABS(GEN(N)-GENH(N))
C
C     CONVERGENCE TEST FOR GENERATION
C
      CT = TOL(N) .GT. (TC*GEN(N)*0.005)
      GENH(N)=GEN(N)
      IF(CT) CYCLE=.FALSE.
  100 CONTINUE
      IGS=IGS+1
      IF(.NOT.CYCLE) GO TO 60
      LOSS=0.0
      SUM=0.0
C
C     CALCULATE SYSTEM LOSS
C
      DO 120 N=1,4
      AUX(N)=B(N,1,NB)*GEN(1)
      SUM=SUM+GEN(N)
      DO 115 M=2,4
      AUX(N)=B(N,M,NB)*GEN(M)+AUX(N)
  115 CONTINUE
      LOSS=LOSS+AUX(N) * GEN(N)
  120 CONTINUE
      PR=SUM-LOSS
      ADJUST=DEMAND(HOUR)-PR
C
C     CONVERGENCE TEST FOR POWER RECEIVED = DEMAND
C
      IF(TC*DEMAND(HOUR)*0.01-ABS(ADJUST)) 125,160,160
  125 IF ( (IC .GE. 2) .AND. (HPR .NE. PR) ) GO TO 140
  130 HLAM1=LAMBDA
      HPR=PR
C
C     STEP ADJUSTMENT OF LAMBDA
C
      LAMBDA = LAMBDA*( 1.0+ADJ(K)*ADJUST)
      GO TO  150
  140 HLAM2=LAMBDA
C
C     LINEAR INTERPOLATION FOR NEXT VALUE OF LAMBDA
C
      LAMBDA=HLAM2+ADJUST*(HLAM2-HLAM1)/(PR-HPR)
```

```
0093           HLAM1=HLAM2
0094           HPR=PR
0095       150 IC=IC+1
         C
         C     TEST FOR LAMBDA LIMIT
         C
0096           IF ( LAMBDA .LT. LAMN ) LAMBDA=LAMN
0097           IF ( LAMBDA .GT. LAMX ) LAMBDA=LAMX
         C
         C     TEST FOR SLOW CONVERGENCE DUE TO GENERATION CONSTRAINTS
         C
0098           IF ( (IC .GT. 3) .AND. (IGS .EQ. 2) ) GO TO 210
0099           GO TO 30
0100       160 DO 165 I=1,4
         C
         C     CALCULATE WATER USED (FLOW)
         C
0101           WUSD(I) = (WP(I)*GEN(I)+WC(I))*GEN(I)/A + WUSD(I)
0102           SHGEN(I,HOUR) = GEN(I)
0103           SP(I,HOUR) = ETC(1)
0104           IF((GEN(I).GE.GMAX(HOUR,I)).OR.(GEN(I).LE.GMIN(HOUR,I)))SP(I,HOUR)
              1=ETC(2)
0105       165 CONTINUE
0106           IF ( .NOT. FIRST ) GO TO 170
0107           AGEN(1) = 0.62440*GEN(1)
0108           AGEN(2) = 0.25430*GEN(1)
0109           AGEN(3) = 0.12130*GEN(1)
0110           IF ( GEN(2) .GT. 20.0 ) GO TO 167
0111           AGEN(4) = 12.0
0112           AGEN(5) = GEN(2) - 12.0
0113           GO TO 168
0114       167 AGEN(4) = 0.42*GEN(2)
0115           AGEN(5) = 0.58*GEN(2)
0116       168 AGEN(6) = GEN(3)
0117           AGEN(7) = GEN(4)
0118           SPNR = 0.0
0119           DO 169 I=1,7
0120           INT = AGEN(I)/MACH(I) + 1
0121           CAP = INT*MACH(I)
0122           SPNR = CAP - AGEN(I) + SPNR
0123       169 CONTINUE
0124           SUMG(1,HOUR) = SUM
0125           SUMG(2,HOUR) = LOSS
0126           SUMG(3,HOUR) = PR
0127           SUMG(4,HOUR) = LAMBDA
0128           SUMG(5,HOUR) = SPNR
         C
         C     PRINT GENERATION FOR HOUR IF PRINTOUT NOT SUPPRESSED
         C
```

```
      IF ( PRINT ) WRITE(6,701) ((GEN(I),SP(I,HOUR)),I=1,4),SUM,LOSS,PR,
     1 LAMBDA,SPNR,HOUR
  701 FORMAT(/T7,4(F7.2,A4),13X,F10.2,2F12.2,F13.4,F12.2,I6/)
C
C     STORE UPDATED VALUE OF LAMBDA,(FOR BASE CASE INITIALLY)
C
      HRLAMB(HOUR) = LAMBDA
C
C     INCREMENT HOUR AND TEST FOR COMPLETION OF HOURLY SCHEDULE
C
  170 HOUR = HOUR + 1
      IF(HOUR.LE.A) GO TO 10
      IF ( .NOT. FIRST ) GO TO 175
      IF ( LSQV .EQ. 0 ) PLSQV = SLSQV
      SLSQV = 0.0
  175 DO 200 I=1,4
      MPR(I) = ETC(1)
      IF(FIRST) GO TO 185
C
C     CALCULATE JACOBIAN ELEMENT DQ/D(GAMMA)
C
      QGAM(I,K)=(WUHD(I)-WUSD(I))/(GAMARY(K)-GAMMA(K))
      GO TO 200
  185 IF ( WATER(I) .EQ. 0.0 ) GO TO 188
C
C     CALCULATE RESIDUE (DEVIATION FROM REQUIRED WATER USAGE) AND GAMMA
C     CHANGE FOR NEXT PERTURBATION. MAXIMUM CHANGE 5 (
      DEV(I) = WUSD(I) - WATER(I)
C
C     CALCULATE VALUE OF OBJECTIVE FUNCTION.
C
      SLSQV = DEV(I)*DEV(I)*1.0E4/(WATER(I)*WATER(I)) + SLSQV
  188 WUHD(I) = WUSD(I)
      IF(DEV(I)) 195,190,195
  190 DEV(I) = (WUSD(I)-(WMIN(I)+WMAX(I))*0.5)*0.01
  195 GADJ(I)=GAMARY(I)*0.00005*DEV(I)
      IF(ABS(GADJ(I)).GT.0.05*GAMARY(I)) GADJ(I)=DSIGN(0.05D0*GAMARY(I),
     1DEV(I))
      IF( (WUSD(I).GE.WMAX(I)) .OR. (WUSD(I).LE.WMIN(I)) ) MPR(I)=ETC(2)
  200 CONTINUE
C
C     PRINT MEAN FLOW
C
      IF ( PRINT ) WRITE(6,702) ( (WUSD(I),MPR(I)),I=1,4 )
  702 FORMAT(/T24,'( AVERAGE FLOWS ( CUSECS ) )'//T8,4(F7.0,A4)//)
      RETURN
C
C     CONVERGENCE CORRECTION PROCEDURES -
C
```

```
      C
      C     TEST FOR NEGATIVE GAMMA.
      C
0155    210 DO 212 I=1,4
0156        IF ( GAMARY(I) .LE. 0.0 ) GO TO 250
0157    212 CONTINUE
      C
      C     TEST FOR DIRECTION OF LAMBDA MOVEMENT. IF STATIONARY THEN
      C     DEMAND OUTSIDE RANGE OF SYSTEM GENERATION.
      C
0158        IF ( LAMBDA - HLAMI ) 214,240,218
      C
      C     SEARCH FOR NEAREST LOWER MAXIMUM TO CURRENT LAMBDA VALUE
      C     AND ASSIGN TO LAMBDA
      C
0159    214 TLM = LAMN
0160        DO 216 I=1,4
0161        IF ( (GLAMX(I) .LT. LAMBDA) .AND. (GLAMX(I) .GE. TLM) ) TLM =
           1 GLAMX(I)
0162    216 CONTINUE
0163        GO TO 222
      C
      C     SEARCH FOR NEAREST HIGHER MINIMUM TO CURRENT LAMBDA VALUE
      C     AND ASSIGN TO LAMBDA
      C
0164    218 TLM = LAMX
0165        DO 220 I=1,4
0166        IF ( (GLAMN(I) .GT. LAMBDA) .AND. (GLAMN(I) .LT. TLM) ) TLM =
           1 GLAMN(I)
0167    220 CONTINUE
      C
      C     RESTART LAMBDA ITERATION TO SATISFY DEMAND.
      C
0168    222 LAMBDA = TLM
0169        IC = 1
0170        GO TO 30
0171    240 WRITE(6,710)
0172    710 FORMAT('0    DEMAND OUTSIDE RANGE OF AVAILABLE GENERATION.'/)
0173        RETURN 1
      C
      C     RESET NEGATIVE GAMMA TO GAMMA EQUIVALENT TO 5 % CHANGE.
      C
0174    250 DO 252 I=1,4
0175        IF ( GAMARY(I) .GT. 0.0 ) GO TO 252
0176        GAMARY(I) = HGAM(I) + SIGN(0.05*HGAM(I),(GAMARY(I)-HGAM(I)) )
0177    252 CONTINUE
0178        IF ( K .LT. 5 ) WRITE(6,712)
0179    712 FORMAT('0   TEMPORARY GAMMA -VE.  RE-INPUT DATA. '/)
      C
```

```
              C      RESTART SCHEDULE FOR NEW BASE CASE.                                GENL2930
              C                                                                         GENL2940
 0180                RETURN 2                                                           GENL2950
 0181                END                                                                GENL2960
```

```
      SUBROUTINE PAREQ(NEQ,AV,*)
      REAL*8 RHS(4),CORR(4),QGAMS(16),DET
      COMMON  QGAM,DEV,GAMMA(4),HGAM(4),WBYP(4)
      REAL*8 QGAM(4,4),DEV(4)
      INTEGER WBYP
      DIMENSION LWK(4),MWK(4)
C
      II=0
      IJ=0
C
C     QGAM AND DEV REDUCED TO SINGLE DIMENSION VECTORS AND QGAM IS
C     NORMALISED AT THE SAME TIME. NOTE RHS(DEV) IS DIVIDED BY
C     DIAGONAL ELEMENT TO RETAIN CORRECT SOLUTION
C
      DO 210 I=1,4
      IF(WBYP(I).EQ.I) GO TO 210
      II=II+1
      RHS(II)=DEV(I)/QGAM(I,I)
      DO 205 J=1,4
      IF(WBYP(J).EQ.J) GO TO 205
      IJ=IJ+1
      QGAMS(IJ)=QGAM(J,I)/QGAM(J,J)
  205 CONTINUE
      IF ( QGAM(I,I) .LT. 0.0 ) GO TO 260
  210 CONTINUE
C
      CALL MINV(QGAMS,NEQ,DET,LWK,MWK)
C
      IF ( DABS(DET) .LT. 1.0D-12 ) GO TO 260
C
C     CALCULATE GAMMA CORRECTIONS.(PLACED IN CORR)
C
      DO 240 I=1,NEQ
      CORR(I)=QGAMS(I)*RHS(1)
      DO 235 J=2,NEQ
      CORR(I)=CORR(I)+QGAMS(I+NEQ*(J-1))*RHS(J)
  235 CONTINUE
  240 CONTINUE
C
C     CALCULATE NEW GAMMA VALUES
C
      II=0
      AV=0.0
      DO 250 I=1,4
      HGAM(I) = GAMMA(I)
      IF(WBYP(I).EQ.I) GO TO 250
      II=II+1
      IF ( DABS(CORR(II)) .GE. GAMMA(II) ) CORR(II) = CORR(II)*0.01D0
      AV = AV + CORR(II)/GAMMA(II)
```

```
0036          GAMMA(I)=GAMMA(I)+CORR(II)
0037      250 CONTINUE
        C
0038          RETURN
        C
        C     ERROR RETURN
        C
0039      260 WRITE(6,710)
0040      710 FORMAT('0  DETERMINANT LESS THAN 1.0D-12, OR JACOBIAN DIAGONAL NEG
             1ATIVE.'/)
0041          RETURN 1
0042          END
```

```
      SUBROUTINE MINV(A,N,D,L,M)
      DIMENSION A(1),L(1),M(1)
      DOUBLE PRECISION A,D,BIGA,HOLD
      D=1.0
      NK=-N
      DO 80 K=1,N
      NK=NK+N
      L(K)=K
      M(K)=K
      KK=NK+K
      BIGA=A(KK)
      DO 20 J=K,N
      IZ=N*(J-1)
      DO 20 I=K,N
      IJ=IZ+I
   10 IF( DABS(BIGA)- DABS(A(IJ))) 15,20,20
   15 BIGA=A(IJ)
      L(K)=I
      M(K)=J
   20 CONTINUE
      J=L(K)
      IF(J-K) 35,35,25
   25 KI=K-N
      DO 30 I=1,N
      KI=KI+N
      HOLD=-A(KI)
      JI=KI-K+J
      A(KI)=A(JI)
   30 A(JI) =HOLD
   35 I=M(K)
      IF(I-K) 45,45,38
   38 JP=N*(I-1)
      DO 40 J=1,N
      JK=NK+J
      JI=JP+J
      HOLD=-A(JK)
      A(JK)=A(JI)
   40 A(JI) =HOLD
   45 IF(BIGA) 48,46,48
   46 D=0.0
      RETURN
   48 DO 55 I=1,N
      IF(I-K) 50,55,50
   50 IK=NK+I
      A(IK)=A(IK)/(-BIGA)
   55 CONTINUE
      DO 65 I=1,N
      IK=NK+I
      HOLD=A(IK)
```

```
      IJ=I-N
      DO 65 J=1,N
      IJ=IJ+N
      IF(I-K) 60,65,60
   60 IF(J-K) 62,65,62
   62 KJ=IJ-I+K
      A(IJ)=HOLD*A(KJ)+A(IJ)
   65 CONTINUE
      KJ=K-N
      DO 75 J=1,N
      KJ=KJ+N
      IF(J-K) 70,75,70
   70 A(KJ)=A(KJ)/BIGA
   75 CONTINUE
      D=D*BIGA
      A(KK)=1.0/BIGA
   80 CONTINUE
      K=N
  100 K=(K-1)
      IF(K) 150,150,105
  105 I=L(K)
      IF(I-K) 120,120,108
  108 JQ=N*(K-1)
      JR=N*(I-1)
      DO 110 J=1,N
      JK=JQ+J
      HOLD=A(JK)
      JI=JR+J
      A(JK)=-A(JI)
  110 A(JI) =HOLD
  120 J=M(K)
      IF(J-K) 100,100,125
  125 KI=K-N
      DO 130 I=1,N
      KI=KI+N
      HOLD=A(KI)
      JI=KI-K+J
      A(KI)=-A(JI)
  130 A(JI) =HOLD
      GO TO 100
  150 RETURN
      END
```

APPENDIX B

AN OUTLINE OF THE DERIVATION OF THE LOSS FORMULA COEFFICIENTS (REFERENCE 3)

An accurate mathematical model of the transmission system is necessary to enable calculation of the losses for a given generation schedule. Such a model has been developed by G. Kron through the application of the laws of circuit transformation, which permit the development of equivalent circuits, such that the losses remain invariant. These transformation matrices allow logical and systematic analysis and orderly computational procedures which are ideally suited to the digital computer.

Let original circuit quantities have subscript old.

Let new circuit quantities have subscript new.

Kron has shown that if a set of currents $\bar{i}_{old}$ describing the old circuit is related to the new currents $\bar{i}_{new}$ by a transformation matrix $\bar{C}$ such that -

$$\bar{i}_{old} = \bar{C} \; \bar{i}_{new}$$

and if power is to remain invariant, the new set of voltages is given by -

$$\bar{e}_{new} = \bar{C}_t{}^* \; \bar{e}_{old}$$

and the new set of impedances is given by -

$$\bar{Z}_{new} = \bar{C}_t{}^* \; \bar{Z}_{old} \; \bar{C}$$

where $\overline{C}_t^*$ is the matrix obtained by conjugating the elements of transpose matrix $\overline{C}_t$.

Kron has denoted the steps in the analysis by reference frames. The derivation of a transmission loss formula starts by considering the system network in terms of the self and mutual impedances between generators and loads, and a reference bus in the network as shown in figure B1 (reference frame 1).

The currents treated as variables are the generator and load currents. By assuming that the individual load currents remain a constant complex fraction of the total load current, the circuit of reference frame 1 is modified to that of reference frame 2 (figure B2).

Now all the load currents have been replaced by a total load current. If the total load current is assumed equal to the sum of the generator currents, reference frame 3 (figure B3) is obtained, with the load current no longer as a variable.

A transmission loss formula ideally contains only generator powers as variables. The generator currents are then transformed into generator powers by assuming that the:-

(a) generator voltage magnitudes remain constant

(b) generator angles remain constant

(c) generator reactive requirements are a linear function of the generator outputs and system loads.

Using these assumptions Kron transforms the network from reference frame 3 into terms of generator power

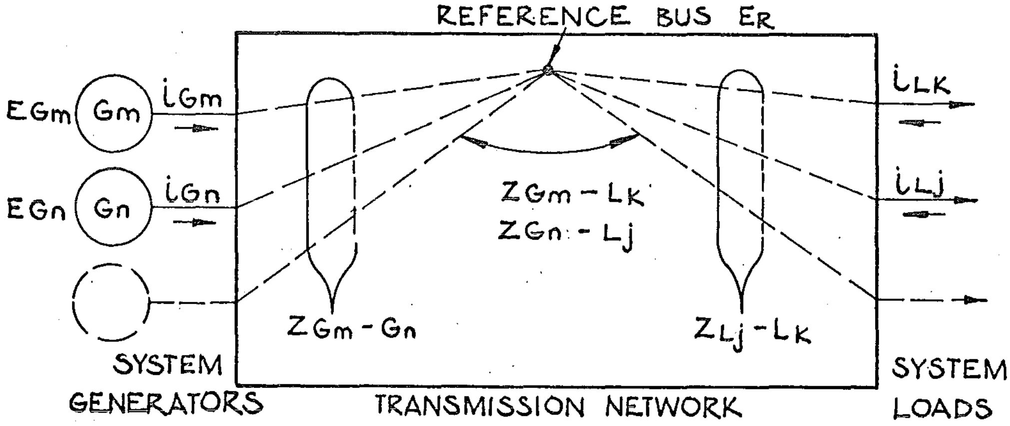

fig. B1 REFERENCE FRAME 1.
SELF & MUTUAL IMPEDANCES BETWEEN GENERATORS, LOADS & REFERENCE BUS

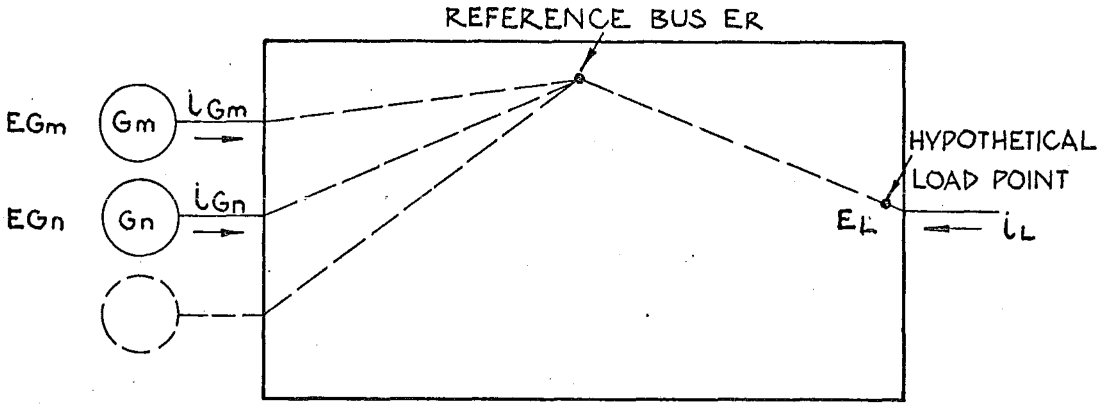

fig. B2 REFERENCE FRAME 2:
INDIVIDUAL LOADS ELIMINATED AS VARIABLES

with reference frame 6 resulting (figure B4).

By evaluating the transmission losses in reference frame 6, the loss formula is obtained -

$$P_L = \sum_m \sum_n P_m B_{mn} P_n$$

where P_L = system loss

P_m, P_n = generator power output

B_{mn} = loss formula (B) coefficients

To determine the B coefficients, system data is required. The open circuit impedances and representative load data obtained from load flow calculations, together with the approximate linear relationship between the generator real and reactive power outputs, constitutes the required data. Proceeding as in Kirchmayer (Chapter 4) the B coefficients may be obtained for a number of representative load cases for use in calculating the losses in the economic load scheduling program.

The B_{mn} represent an equivalent loss network through which the generator powers flow in satisfying the system load. Since $B_{mn} = B_{nm}$ the number of loss formula coefficients to be calculated for a loss formula with n sources = $\left[n(n+1)\right]/2$.

The relative magnitudes of the B_{mn} terms may be estimated from a knowledge of the physical transmission system. Those sources which are the greatest distances away from the system load will have the largest self (B_{mm})

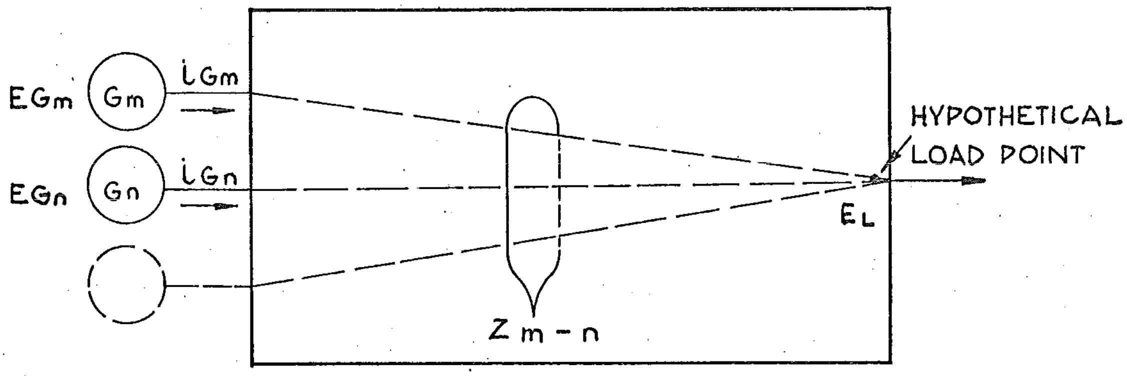

fig. B3 REFERENCE FRAME 3.

TOTAL LOAD ELIMINATED AS VARIABLE

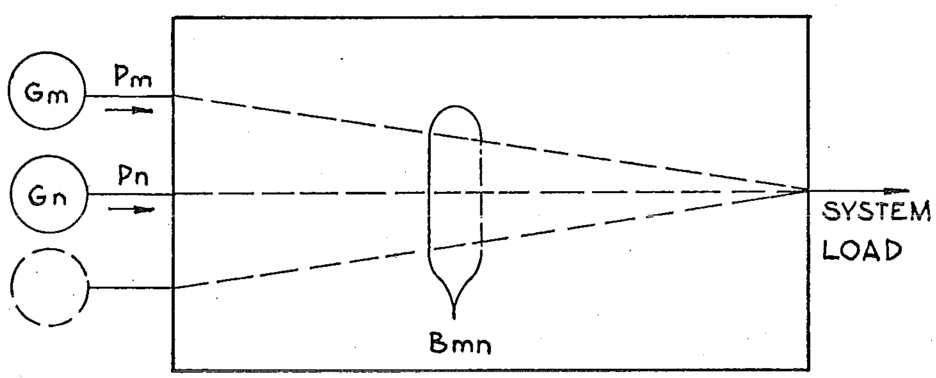

fig. B4. REFERENCE FRAME 6

EQUIVALENT CIRCUIT WITH IMPRESSED GENERATOR POWERS terms. Sources close to each other usually have positive mutual terms, and sources at opposite ends of the system usually have negative mutual terms. The self term must always be positive and is generally the largest positive number in that row or column of the B coefficient matrix.

Typical Results from Program LFBCOP

$$s = \frac{Q_m}{P_m} \quad \text{ratio for generator } m$$

$$Q_m = Q_{Lm} + s_m \; P_m$$

where Q_{Lm} = reactive power component of plant m included in load at bus m

P_m = real power output generator m

Q_m = reactive power output generator m

Input: Data Set 1.

Bus n	Name	Volts (p.u)	Angle (deg)	Generation (MW)	Load (MW)	(MVAR)	Plant CONST* (MVAR)	Characteristics S
1	WAIT	1.050	-0.0	3.244	0.600	0.050	0.200	-0.150
2	HBCL	1.099	-10.70	0.540	0.0	0.0	0.139	0.0
3	COBB	1.003	-21.10	0.320	0.760	0.200	0.010	0.0
4	ROXB	1.050	1.00	1.600	1.100	0.050	0.005	-0.100
5	LIVG	1.045	-2.40	0.0	0.0	0.0	-0.305	0.0
6	ISLN	1.000	-15.80	0.0	3.063	0.350	-0.451	0.0

"LOADFLOW" system loss = 0.18401

*CONST - constant component at Bus n: includes Q_{Lm} and line changing MVARs.

Typically three sets of data are input and the B coefficients obtained for each data set and the average values.

Output:

(i) Coefficients (Data Set 1) -

0.010305	-0.001851	0.005500	0.001609
-0.001851	0.109871	-0.001168	-0.006816
0.005500	-0.001168	0.027066	-0.010951
0.001609	-0.006816	-0.010951	0.025527

(ii) B Coefficients (Average) -

0.010227	-0.001913	-0.005597	0.001618
-0.001913	0.109820	-0.001243	-0.006740
-0.005597	-0.001243	0.026971	-0.011104
0.001618	-0.006740	-0.011104	0.025498